PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 30, 2018

VIA ELECTRONIC FILING,
HUDDLE AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: Advice No. 18-003/UE 339—PacifiCorp's 2019 Transition Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power 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. PacifiCorp requests an effective date of January 1, 2019.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2019 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The following proposed tariff sheets are provided in Ms. Ridenour's Exhibit PAC/302. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Michael G. Wilding, Director, Net Power Costs
- Dana M. Ralston, Senior Vice President, Thermal Generation and Mining
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

Ninth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Ninth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Ninth Revision of Sheet No. 201-3	Schedule 201	Net Power Costs – Cost-Based Supply Service

PacifiCorp will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—once the final TAM rates have been posted and are known. The transition adjustment rates will be established in November, just before the open enrollment window.

C. Requirements of OAR 860-022-0025 and OAR 860-022-0030

To support the proposed rates and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, PacifiCorp provides the description and support indicated in Section A above. Please refer to the exhibits of Ms. Ridenour for the calculation of the proposed rate changes and impacts of proposed price changes by rate schedule.

This proposed change will affect approximately 614,000 customers, and would result in an overall annual rate increase of approximately $16.9 million or 1.3 percent. Residential customers using 900 kWh per month would see a monthly bill increase of $1.12 per month as a result of this change.

D. Correspondence

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

Oregon Dockets
PacifiCorp
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oregondockets@pacificorp.com

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Katherine@mrg-law.com

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
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to me at (503) 813-6583.

A copy of this filing has been served on all parties to PacifiCorp's 2018 TAM proceeding, docket UE 323. Confidential material in support of the filing has been provided to parties under Order No. 16-128. Highly confidential material in support of the filing has been provided under Order No. 18-106.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

Enclosures

cc: UE 323 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's 2019 Transition Adjustment Mechanism on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

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UE 323

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Dated this 30th day of March, 2018.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 339
Exhibit PAC/100
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Michael G. Wilding

March 2018

DIRECT TESTIMONY OF MICHAEL G. WILDING

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ATTACHED EXHIBITS

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

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

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting degree from Weber State University and a Bachelor of Science degree in accounting from Utah State University. I am a Certified Public Accountant licensed in the state of Utah. Before joining the company, I was employed as an internal auditor for Intermountain Healthcare and an auditor for the Utah State Tax Commission. I have been employed by the company since February 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Utility Commission of Oregon (Commission), and the public utility commissions in Washington, California, Idaho, Utah, and Wyoming.

PURPOSE OF TESTIMONY

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

A. I present the company's proposed 2019 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing;
- Defines NPC and describes the NPC increase in the 2019 TAM compared to the final NPC in the company's previous TAM, docket UE 323 (2018 TAM);

- Describes the major cost drivers in the 2019 TAM;
- Reports on the successful collaborative process required by the Commission's order in the 2018 TAM,[1] and describes modeling changes the company is proposing as a result of the collaborative process;
- Provides the company's proposal to transfer renewable energy certificates (RECs) to electric service suppliers (ESS) to account for departing direct access load; and
- Provides details on the calculation of the Consumer Opt-Out Charge applicable to PacifiCorp's five-year direct access program and describes how the company proposes to change the calculation in response to the Commission's direction in the 2018 TAM.

Q. Please identify the other PacifiCorp witnesses supporting the 2019 TAM.

A. Two additional company witnesses provide testimony supporting the company's filing. Mr. Dana M. Ralston, Senior Vice President, Thermal Generation and Mining, provides testimony supporting the coal costs included in the 2019 TAM. Ms. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

SUMMARY OF PACIFICORP'S 2019 TAM FILING

Q. Please provide background on PacifiCorp's 2019 TAM filing.

A. The TAM is PacifiCorp's annual filing to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2019 TAM also includes test period forecasts for: (1) Other Revenues as stipulated in docket UE 216; (2) incremental benefits and costs related to the company's participation in the energy imbalance market (EIM) with the California Independent

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 (Nov. 1, 2017).

System Operator Corporation (CAISO); and (3) renewable energy production tax credits (PTCs). The company is filing the 2019 TAM on a stand-alone basis without a general rate case and proposes that new rates become effective on January 1, 2019.

As shown in Exhibit PAC/101, the 2019 TAM results in an increase to Oregon rates of approximately $16.9 million (unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis). As explained in Ms. Ridenour's testimony, the 2019 TAM results in an overall average rate increase of approximately 1.3 percent.

Q. What are the estimated NPC in the TAM for calendar year 2019?

A. The forecasted normalized NPC for calendar year 2019 are approximately $386.9 million.[2] This is approximately $21.6 million higher than the forecast NPC of approximately $365.3 million in the 2018 TAM. Details of total-company NPC for 2019 are provided in Exhibit PAC/102.

Q. Does the proposed rate increase for the 2019 TAM reflect changes in Oregon load since the 2018 TAM?

A. Yes. The 2019 load forecast used in the company's calculation of NPC reflects an increase in Oregon load compared to the 2018 forecast loads in the 2018 TAM. Due to the increase in Oregon load, the company anticipates it will collect $15.5 million more than expected for NPC based on the rates approved in the 2018 TAM, therefore limiting the overall rate increase for the 2019 TAM.

Q. Have Oregon's allocation factors changed since the 2018 TAM?

A. Yes. The change in Oregon load relative to load in other states served by the

[2] PAC/101, Wilding/1, line 33.

company results in an increase in Oregon's allocation factors and the corresponding share of total-company NPC allocated to Oregon compared with the 2018 TAM. In the 2019 TAM, Oregon's system energy (SE) factor increased by 1.136 percent from 24.186 percent to 25.322 percent, and the system generation (SG) factor increased by 0.984 percent from 25.741 percent to 26.725. Of the $21.6 million increase in forecast NPC identified above, $16.4 million of the increase is driven by the change in allocation factors.

Q. How does the load forecast for the 2019 TAM compare to the load forecast used for the 2018 TAM?

A. The 2019 forecast loads, on a total-company basis, are 0.21 percent higher than the forecast loads used in the 2018 TAM. Oregon 2019 forecast loads are 700 GWh (4.9 percent) higher than the forecast loads used in the 2018 TAM. The forecasted loads for Washington and Idaho also increase, while the forecasted loads for Utah and Wyoming decrease. Table 1 below shows the changes between the load forecasts for all states.

Table 1

Table 1 Total Company Sales at System Input by Jurisdiction (GWh)				
	2018 Previous TAM Forecast	2019 Current TAM Forecast	GWh Change	Percentage Change
Oregon	14,243	14,943	700	4.9%
Washington	4,359	4,471	112	2.6%
California	879	879	0	0.0%
Utah	25,420	24,725	-694	-2.7%
Idaho	3,793	3,857	65	1.7%
Wyoming	9,921	9,847	-74	-0.7%
FERC*	306	322	16	5.4%
Total	58,920	59,045	125	0.21%

*Includes sales for resale

Q. What are the major drivers for the changes between the load forecasts in the 2018 TAM and the 2019 TAM?

A. The changes to forecast load between the 2018 TAM and the 2019 TAM are attributable to a combination of factors. The 2019 TAM includes an additional year of historical data (March 2016 to February 2017) in the load forecasting model. Further, the 2019 TAM includes updates to load forecasts based on economic, customer, and industry data. In Oregon, the significant drivers in the 2019 TAM load forecast include more optimistic forecasts for large commercial customers and the incorporation of the additional year of historical sales. The lower forecast load in Utah is attributable to a decrease in large industrial customer load and an increase in private generation. The Wyoming forecast is lower due to less favorable projections for large industrial customers. The higher Washington forecast load is attributable to improved projections for the transportation and warehousing related industries, while the higher forecast for Idaho is attributable to a more optimistic outlook for the irrigation class.

Q. What is the net impact to the 2019 TAM due to the change in Oregon load?

A. The increased Oregon allocation factors account for an increase to the TAM of $16.4 million and the change in the 2018 TAM load forecast accounts for a decrease of $15.5 million. Thus, the net impact of increased Oregon load is $0.9 million.

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

A. Yes. Exhibit PAC/103 shows the update to "Other Revenues" compared to the level set in the 2018 TAM. Other Revenues reflect an increase in production and price, per the terms of the agreement, of the Seattle City Light State Line wind farm contract. Projected Other Revenues are approximately $0.03 million lower in 2019.[3] However, as explained in Ms. Ridenour's testimony, this amount is too small to result in a rate change to Schedule 205, TAM Adjustment for Other Revenues.

Q. Please explain how the benefits and costs associated with participation in the EIM are treated in the 2019 TAM.

A. PacifiCorp's initial filing includes both the benefits and costs associated with participation in the EIM. The expected incremental EIM benefits relative to the optimized NPC modeled by the Generation and Regulation Initiative Decision Tools model (GRID) are reflected as a reduction to the NPC forecast. As discussed later in my testimony, the total-company EIM benefits included in the 2019 TAM are $29.3 million, a decrease of $10.9 million in benefits from the 2018 TAM. EIM-related costs, including capital and operations and maintenance (O&M) expense, are added to the TAM to match the benefits. The Commission approved this same treatment in the 2016, 2017, and 2018 TAMs, and it is consistent with the stipulation in docket UE 287 (2015 TAM), which first addressed EIM-related costs in the TAM. Details supporting EIM benefits and costs are included in Confidential Exhibit PAC/104 and Exhibit PAC/105.

Q. Has PacifiCorp's calculation of EIM benefits changed in this filing?

A. Yes. The 2019 EIM inter-regional benefit was estimated by extrapolating forward a linear trend based on the EIM benefit by month beginning in December 2015. This

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

change is being made because the company now has sufficient data that captures the full seasonality of new entrants. Notably, the historical data before December 2015 is not used because of the steep learning curve experienced by the company from participating in a new market. Additionally, before December 2015 the only EIM participants were PacifiCorp and CAISO, which limited transmission.

Q. Please describe the treatment of renewable energy PTCs in the 2019 TAM.

A. Consistent with Section 18(b) of Senate Bill 1547 and the Commission's order in the 2017 TAM,[4] the 2019 TAM includes changes in its projected PTCs in this filing. Exhibit PAC/106 shows the forecast level of PTCs for 2019 compared to the level of PTCs established in the 2018 TAM. Based on the expiration of PTCs at several company-owned facilities, the forecast of Oregon-allocated PTCs for the 2019 test period is approximately $5.9 million, which is down from the $17.2 million included in the 2018 TAM, resulting in an increase to the 2019 TAM of $11.2 million. The change in PTCs is driven by the decrease to the federal income tax rate, the expiration of PTCs at certain facilities, and a decreased capacity factor used in the NPC forecast.

Q. Please explain the change in PTCs due to the change in the federal income tax rate.

A. The Tax Cuts and Job Act was effective January 1, 2018, and decreased the corporate federal income tax rate to 21 percent. The change in tax law decreases the value of the income tax credit received from the PTC and thus increases the 2019 TAM. Additionally, the tax law change also impacts the PTCs included in the 2018 TAM.

[4] *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-418 (Oct. 27, 2016). The Commission did not specifically discuss the modeling of PTCs, but PacifiCorp agreed to Staff's proposed methodology and the Commission accepted that approach.

This will be addressed in PacifiCorp's federal tax deferral filing in docket UM 1917 and a request for amortization that will be filed in the second quarter of 2018.

Q. Are the impacts of repowering included in the 2019 TAM?

A. No. The company's 2017 Integrated Resource Plan (IRP) outlines the company's intention to repower its wind fleet beginning in 2019. This project will benefit customers by increasing wind production, a zero-fuel cost resource, thus reducing NPC and by requalifying the wind plants for PTCs. PacifiCorp expects to include the costs and benefits of repowering in a renewable adjustment clause deferral filing in 2019.

DETERMINATION OF NPC

Q. Please explain NPC.

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

Q. How does the TAM relate to NPC?

A. In the 2017 TAM Order, the Commission described the TAM and its purpose as follows:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[5]

[5] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).

Q. Please explain how PacifiCorp calculates NPC.

A. PacifiCorp calculates NPC for a future test period based on projected data using GRID, which is a production cost model that simulates the operation of the company's power system on an hourly basis.

Q. Has the company improved the accuracy of the NPC forecasts in the TAM through recent modeling changes?

A. Yes. In previous TAM proceedings, PacifiCorp's NPC was systematically under-stated. In the 2016 TAM, the company proposed and the Commission adopted multiple modeling improvements designed to produce a more accurate NPC forecast. Many of the same modeling improvements were affirmed in the 2017 and 2018 TAMs, subject to further refinements.

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. PacifiCorp has used the GRID model to determine NPC in its Oregon filings since 2002. Over time, the company has implemented various improvements to the modeling of specific items in GRID to better reflect company operations and to achieve the most accurate NPC forecast for the test period.

Q. Has the company proposed any changes to the GRID model in the 2019 TAM?

A. No. PacifiCorp used the same version of the GRID model in the 2019 TAM that it used in the 2018 TAM, subject to the modeling refinements discussed below related to coal plant dispatch.

Q. What inputs were updated for this filing?

A. The company updated all inputs to the 2019 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the company's generation facilities.

Q. What is the date of the Official Forward Price Curve the company used in this filing?

A. PacifiCorp's filing uses an Official Forward Price Curve (OFPC) dated December 29, 2017.

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

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

Q. What reports does the GRID model produce?

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

DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2019 TAM.

A. The increase in NPC is driven by a reduction in wholesale sales revenue and an increase in natural gas fuel expenses. The increase is partially offset by reductions in coal fuel expense and wheeling expense. Table 2 illustrates the change in total-company NPC by category from the NPC baseline in the 2018 TAM.

Table 2
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2018	**$1,483**	**$25.20**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	71	
Purchased Power Expense	(24)	
Coal Fuel Expense	(92)	
Natural Gas Fuel Expense	73	
Wheeling and Other Expense	(9)	
Total Increase/(Decrease) to NPC	**18**	
OR TAM 2019	**$1,501**	**$25.46**

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower sales volumes and lower prices for wholesale market sales transactions. Market sales (represented in GRID as short-term firm and system balancing sales) in the 2018 TAM were included at an average price of $26.98/MWh, while market sales in the current case are included at an average price of $26.55/MWh, a two percent decline in price. Total wholesale sales volume is of 2,191 GWh lower than what in 2018 TAM.

Q. Why did purchased power expense decrease?

A. The decrease in purchased power expense is due to a forecast reduction in the volume of purchased power and slightly lower market purchase prices. The volume of purchased power from market purchases (represented in GRID as short-term firm and system balancing purchases) in the 2019 TAM is 2,102 GWh lower than the 2018

TAM. Market purchases in the current case are included at an average price of $21.10/MWh, while the 2018 TAM used an average price of $21.30/MWh, a one percent decrease.

The reduction in purchased power expense is offset by the increase in total expense for power purchased from Qualifying Facilities (QFs), which increased by approximately $27.2 million (total-company) compared to the 2018 TAM. The increase is attributed to several Solar QFs in Oregon and Utah that are expected to operate during the entire test period of 2019.

Q. Does this case include new QF power purchase agreements (PPAs) that are not yet operational but that are expected to achieve commercial operation before the end of the forecast period?

A. Yes. The company includes three PPAs with QFs that are expected to reach commercial operation in 2019 and have not previously been included in rates. Based on the information known to the company at this time, the company has a commercially reasonable good faith belief that these QFs will reach commercial operation before or during the forecast period.

Q. Did the company apply the contract delay rate (CDR) approved by the Commission in the 2018 TAM?[6]

A. Yes. As described in more detail below, the QF PPA costs included in the 2019 NPC account for the CDR approved by the Commission in the 2018 TAM. The QF delay rate is based on the average days between the QF's expected Commercial Operation Date (COD) in the final TAM and its actual COD or the most recent estimated COD

[6] *See* Order No. 17-444 at 17.

from the last three TAM proceedings. The average days delayed is weighted by the nameplate capacity of the delayed QF in the historical period.

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

A. Yes. Several existing QF PPAs terminate before the end of the forecast period. PacifiCorp assumes these QFs will execute new PPAs to continue selling to the company at the most recent avoided cost rates. The company will update the status of these PPAs as new information becomes available per the TAM Guidelines.

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

A. Total coal fuel expense is $91.9 million lower than the 2018 TAM due to the projected cessation of Naughton Unit 3 as a coal-fired resource and lower coal generation volume from other plants. The increase in coal fuel expense is driven by changes in third-party coal supply and rail contracts since last year's TAM. Mr. Ralston provides additional detail regarding the cost of coal during the test year in his direct testimony.

Q. Please discuss the change in natural gas fuel expense compared to the 2018 TAM.

A. Natural gas fuel expense in the 2019 TAM is $72.8 million higher than the natural gas fuel expense in the 2018 TAM, a 29 percent increase. This increase is due to the lower natural gas market prices which drives increase in the natural gas generation volume. The average cost of natural gas generation decreased from $23.64/MWh in the 2018 TAM to $20.32/MWh in the current case, a 14 percent decrease. Generation from natural gas plants in the 2019 TAM is 5,331 GWh (50 percent increase) more compared to the 2018 TAM.

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

A. Expenses in this category are lower due to a decrease in wheeling expense related to Arizona Public Service Company's firm point-to point contract expiration at the end of 2018.

Q. How are Jim Bridger Units 3 and 4 modeled in the 2019 TAM?

A. In PacifiCorp's 2019 TAM, the minimum operation level of Jim Bridger Units 3 and 4 stays at the level before the environmental upgrades. Selective catalytic reduction systems were placed in operation in November 2015 for Unit 3, and November 2016 for Unit 4. This should not be perceived as PacifiCorp conceding the actual minimum operational level of Units 3 and 4. It is simply to be consistent with the last two TAM proceedings.

Q. **What updates are expected in the company's resource portfolio relative to the 2018 TAM?**

A. The company updated minimum operation level for several thermal plants. The impacts is included Step Log Step 8.

Q. How is Naughton Unit 3 treated in the 2019 TAM?

A. Naughton Unit 3 is assumed to retire at the end of 2018 and therefore is not included in the 2019 TAM initial filing. However, if this date changes with the IRP update or if the IRP updates determines Naughton Unit 3 be converted to natural gas the change will be captured in the rebuttal filing.

COMPLIANCE WITH 2018 TAM ORDER

Q. What requirements did the Commission impose as part of its order in the 2018 TAM?

A. In Order No. 17-444, the Commission provided several directives to PacifiCorp, Staff, and the parties.

First, the Commission directed PacifiCorp to "undertake a limited GRID validation exercise before the 2019 TAM, with the company providing analysis of re-runs of a historical GRID year using actual data[.]"[7] The Commission further directed Staff to provide a status report on the limited model validation process no later than the first public meeting in January 2018.[8] My testimony addresses these directives below.

Second, the Commission directed PacifiCorp to include in the 2019 TAM an updated 2010 coal inventory report.[9] Mr. Ralston's testimony addresses this directive.

Third, the Commission directed PacifiCorp and the parties to participate in a coal workshop to address the following issues:

- PacifiCorp's process by which the terms and conditions of long-term coal contracts are developed, negotiated and approved, and how the company accounts for plant fuel requirements when negotiating long-term contracts or coal mine investment decisions;
- PacifiCorp's process for managing risk in long-term coal contracts related to: (a) price; (b) contract length; (c) minimum take provisions; (d) liquidated damages; and (e) changing electricity market conditions;

[7] Order No. 17-444 at 5.
[8] Order No. 17-444 at 21.
[9] Order No. 17-444 at 21.

- How long-term coal contract provisions impact dispatch decisions in GRID, commitment decisions, and long-term system modeling decisions;
- How (a) long-term coal contracts, (b) fuel transportation contracts, and (c) spot market coal fuel purchases are each reviewed before the Commission;
- The potential development of a method to reflect variable operations and maintenance (O&M) costs in NPC, including classification of which O&M costs should be treated as variable and the treatment of variable O&M in rates; and
- Coal plant economic outage modeling.[10]

The Commission also directed PacifiCorp to make a presentation at a public meeting before the 2019 TAM summarizing the coal workshops. This presentation occurred on March 13, 2018. My testimony addresses how long-term coal contract provisions impact dispatch decisions in GRID, commitment decisions, and long-term system modeling decisions; the treatment of variable O&M costs in NPC; and the coal plant economic cycling modeling. Mr. Ralston's testimony addresses the remainder of the Commission's directives.

Fourth, the Commission directed PacifiCorp to conduct a party workshop on REC transfers before the 2019 TAM filing.[11] PacifiCorp is also required to include in its 2019 TAM direct testimony a proposal for REC transfers for parties and the Commission to consider. My testimony addresses this directive below.

Fifth, the Commission directed PacifiCorp to demonstrate the mechanics of its Consumer Opt-Out Charge calculation consistent with the requirements set forth in the 2018 TAM Order.[12] My testimony addresses this directive below.

[10] Order No. 17-444 at 11.
[11] Order No. 17-444 at 21.
[12] Order No. 17-444 at 21.

Model Validation

Q. Did the company hold workshops to discuss the scope and mechanics of the model validation process, as required by the Commission?[13]

A. Yes. PacifiCorp met with Staff on December 5, 2017, for preliminary discussions. Thereafter, on December 18, 2017, PacifiCorp met with Staff, the Industrial Customers of Northwest Utilities (ICNU), and the Oregon Citizens' Utility Board (CUB) to discuss the scope, inputs, and parameters of the limited model validation ordered by the Commission.

Q. Based on the workshops, did the parties agree on the parameters for the model validation process?

A. Yes. Parties agreed to the following initial set of parameters:

1) Base year is 2016.

2) Base inputs are the final 2016 TAM update inputs.

3) Replace forecast market energy prices with actual hourly prices for each hub with three different scenarios:

   a. POWERDEX Prices;

   b. PacifiCorp actual real time transaction prices; or

   c. Historic Monthly prices shaped using scalers.

4) Replace forecast natural gas prices with actual natural gas prices.

5) Replace forecast load with actual hourly load.

6) Replace forced outage rate and planned outages with actual outages and actual derates.

[13] Order No. 17-444 at 5.

a. Run with/without scenarios for economic shutdowns.

7) Replace forecast wind profile with actual wind profile.

8) Replace forecast hydro conditions with actual hydro conditions.

9) Run a sensitivity study with market caps on and off.

10) Use actual generation profile for long term contracts, PPAs and QFs.

11) Option contracts will be optimized by GRID.

12) Run a sensitivity with actual market transactions of duration greater than 7 days.

13) Use actual heat rate curve.

14) The following items will be updated to reflect major changes not captured in TAM:

a. Wheeling Costs including long term contract changes; and

b. Incremental Coal costs including transport costs.

15) Update Jim Bridger costing tier prices to reflect actual Jim Bridger coal costs.

Q. Did Staff provide a status report to the Commission based on the outcome of the parties' workshop, as required by the Commission?[14]

A. Yes. Staff provided a status report at the Commission's January 3, 2018 public meeting. Staff's public meeting memorandum summarizing the model validation workshops is attached as Exhibit PAC/107. Staff reported that the parties made sufficient progress towards developing an agreed-upon model validation analysis.

[14] Order No. 17-444 at 21.

Q. Did the parties hold any additional model validation workshops?

A. No. However, parties have tentatively agreed to a workshop shortly after the 2019 TAM is filed to review the model validation analysis.

Q. Did PacifiCorp complete the model validation analysis as outlined above?

A. Yes, with the exception of step 3(b), which was the replacement of forecast market energy prices with actual hourly prices realized by PacifiCorp in actual real time transactions at each market hub. This step was not completed because as the company commenced its work on the model validation analysis this proved challenging and did not add value to the analysis. The actual prices realized by the company reflect spot prices at the time of the transaction based on specific volumes, however they do not reflect the prices that all the market participants face in real time based on overall market conditions. The market and operational conditions PacifiCorp experiences may or may not be consistent with the entire market conditions that all the market participants are experiencing. Additionally, there is no evidence that the actual prices realized by the company would be available for the volumes at which GRID transacts. The actual prices used in the steps 3(a) and 3(c) of the model validation analysis are actual average prices representative of the liquid markets to which the company has access.

Q. What are the results of the model validation analysis?

A. The results of the model validation analysis show the GRID model was able to reasonably and accurately simulate historical NPC for the period of 2016. The GRID model estimated total company 2016 NPC to be $1,466.3 million compared to actual costs of $1,465.9 million, a variance of $0.4 million or 0.03 percent. The backcast

2016 NPC study is included as Exhibit PAC/112. The GRID model estimated total resources at 71.8 million MWh compared to 65.0 million MWh, a difference of 6.9 million MWh or 11 percent. Long-term firm sales and long-term firm purchase dollars and MWh are accurately captured in the backcast study, with differences of 0.4 percent and 2.3 percent, respectively, on average. Hydro generation was based on actual hourly hydro generation. For wind generation, PacifiCorp used actual 2016 hourly wind generation with the exception of Rolling Hills Wind, which is included in the company's actual NPC but not in the TAM. Therefore, the variance related to wind generation is due to Rolling Hills' exclusion in the TAM.

The variance between short term and system balancing sales and purchases is driven by the fact that GRID balances the system differently than the company does in actual operation. Also, GRID faces a different set of operational constraints compared to what the company faces in real time. For example, market liquidity in GRID is predetermined based on market cap inputs that allow more sales and purchase transactions than the company's historical experience. Please refer to Confidential Table 3 for a detailed comparison between the backcast study NPC and 2016 Actual NPC.

REDACTED

Confidential Table 3

Net Power Cost Different Summary
BackCast

		GRID	Actual	Difference	Difference %
[redacted]					
Net Power Cost	**$**	**1,466,325,182**	**1,465,887,270**	**437,913**	**0.03%**

		GRID	Actual	Difference	Difference %
[redacted]					
Total Resources	**MWh**	**71,842,918**	**64,957,461**	**6,885,457**	**11%**

Q. How did the company apply the day-ahead/real-time (DA/RT) adjustment in the DA/RT result from the model validation analysis?

A. In the TAM, the DA/RT adjustment has two components: a pricing component and a volume component, as described in further detail later in my testimony. The historical DA/RT cost included in the 2016 TAM is $27.9 million as approved by the Commission in docket UE 296. In the model validation analysis, the company used the actual prices without applying the DA/RT price adders; however, the company did add the incremental balancing volumes associated with using standard products to cover the open position determined by GRID. These volumes are priced such that the overall cost of the company's DA/RT balancing transactions relative to the actual monthly market prices is equal to the historical average.

Q. What is the DA/RT result from the model validation analysis?

A. The pricing component is -$23.1 million and the volume component is $51.0 million.

Q. Please explain the DA/RT result from the model validation analysis.

A. The pricing component value from the model validation is negative, which implies a systematic variance in DA/RT transactions between GRID and real time. In the model validation analysis, the hourly prices used in GRID are equal to the hourly prices in actuals. The backcast shows that GRID transacts at more favorable hourly price points than the transactions in real time based on actual market prices in 2016 resulting in cost savings in GRID. This issue is illustrated in Confidential Figure 1 and Confidential Figure 2 below, which show transaction volumes and prices based on the ranking order of the purchase or sales prices. The related volumes in each ranking category are also summarized. The analysis is based on the Palo Verde (PV) market hub in 2016.

In Confidential Figure 1, 2016 hourly sales prices are ranked from highest to lowest and sorted into seven groups. The corresponding sales volumes from both GRID and actuals are shown for each price group. In the first price group, sales prices ranked one to 100, GRID transacts at an average price of $54.86/MWh, the actual transactions are at an average price of $39.75/MWh, and the average GRID price is 38 percent higher. Additionally, GRID is able to sell energy at higher volumes than actuals, especially during high price hours.

Confidential Figure 2 is constructed in a similar fashion as Confidential Figure 1 for the purchases in the PV market hub. Purchase prices are ranked from lowest to highest and then sorted into seven groups. In the first group, GRID buys at a price of $8.62/MWh compared to $12.59/MWh in actual transactions, 32 percent lower. Additionally, GRID is able to purchase energy at higher volumes than actuals during low price hours. Also notable is that GRID did not make any purchases during the hours with the highest purchase prices. This analysis is based on a one-off study in the model validation process, wherein actual prices are the only data input that change in the GRID model in order to isolate the price impact from changes of other input variables.

Confidential Figure 1

[redacted]

Confidential Figure 2

[redacted]

Q. Does the model validation analysis show that the DA/RT adjustment is just and reasonable?

A. Yes. As shown above, GRID is able to optimize the system to sell when prices are high and buy when purchases are low. This is because GRID balances the system differently than it is balanced in actual operations. First, GRID balances the system with a single hourly transaction. In actual operations, the system is first balanced with monthly transactions, then with day-ahead transactions, and lastly with real-time transactions and only real-time transaction are available for a single hour. Monthly and day-ahead transactions are typically blocks of certain hours over the duration of the transaction. For example, a monthly purchase might deliver energy every

Monday through Saturday of the month for the hours of 6:00 a.m. to 10:00 p.m. Second, GRID can transact at any volume within the inputted market caps. In reality, monthly and day-ahead transactions are done in 25 MW blocks. In the above example, 25 MW would be delivered each hour.

These differences are the drivers for the DA/RT adjustment. For example, if in setting up the system for the day-ahead, the company was in a short position of 37 MW based on tomorrow's system peak and the least cost option was to purchase energy on the market, the company would purchase 50 MW to be delivered each hour from 6:00 a.m. to 10:00 p.m. This is a function of the electric markets in which the company transacts. In contrast, GRID would simply purchase 37 MW to balance the system in that hour.

Lastly, there is no cost of uncertainty in GRID. This means GRID perfectly sets up the current hour for the next hour. In actual operations, the company does experience costs of uncertainty. For example, the forecast wind generation may be more or less than expected or the forecast load may be more or less than expected. GRID does not experience unexpected low loads resulting in additional length to sell into the market at depressed prices nor does GRID experience price spikes when loads are high coupled with lower-than-expected wind generation.

Q. What are the conclusions of the model validation process?

A. First, when actual data is used as inputs, GRID is able to produce the 2016 NPC within a very reasonable range compared to actual 2016 NPC. Second, GRID is designed to produce a forecasted normalized NPC. Given a certain set of input variables, GRID applies its system balancing logic to meet load and wholesale obligations under the operational constraints assumed in the model. In actual operations, the company faces a different set of system constraints. Many of these constraints are not able to be fully reflected in GRID modeling assumptions. For example, GRID is not able to forecast thermal dispatch in the same way that PacifiCorp dispatches its thermal plants in real time. As a result, and as shown in the table above, the coal and natural gas dispatch in GRID was eight percent less and 53 percent more than actuals, respectively.

Third, GRID optimizes the system simultaneously within the established constraints of the inputs. The structure of GRID guarantees that the marginal prices are cost-based and reflect optimized dispatch. Optimal dispatch occurs when the lowest cost generating units that can serve a given load are dispatched first, and generation from higher cost units is minimized. GRID employs a linear program optimization (i.e., optimal dispatch) constrained by: transmission capacity, thermal discretionary availability, purchases and sales market caps, and net load requirements. The GRID result is optimal within these constraints, that is, no net savings can be achieved by backing down one unit and ramping up another unit. In actual operations, as a matter of prudence, PacifiCorp seeks to optimize the system. However, in actual operations, PacifiCorp faces a different set of constraints resulting from actual market conditions, and in real time, system dispatch will choose to balance the system using coal plants, gas plants and system balancing purchases and sales in an order that is feasible to current market conditions. The order of selection of coal plants, gas plants and system balancing purchase and sales results in differences in each resource category compared to the backcast study results.

Day-Ahead and Real-Time System Balancing Transactions

Q. Please describe the DA/RT adjustment that the Commission approved in the 2016, 2017, and 2018 TAMs.

A. PacifiCorp incurs system balancing costs that are not reflected in the company's forward price curve or modeled in GRID. To address this deficiency, in the 2016 TAM, the company proposed the DA/RT adjustment to more accurately model system balancing transaction prices and volumes.

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

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

Q. Please describe the price component of the DA/RT adjustment.

A. To better reflect the market prices available to the company when it transacts in the real-time market, PacifiCorp includes in GRID separate prices for forecasted system balancing sales and purchases. These prices account for the historical price differences between the company's purchases and sales compared to the monthly average market prices.

Q. Why is the DA/RT adjustment needed to differentiate the market prices for purchases and sales?

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

Q. Please describe the volume component of the DA/RT adjustment.

A. The company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the company's forward position in the wholesale market are available in flat 25 MW blocks. The company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, GRID has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of GRID's perfect foresight, it can balance the system with far fewer transactions. The DA/RT adjustment adds additional volumes to NPC to more accurately model the transactions necessary to balance the company's system.

Q. Did parties object to the DA/RT adjustment in the 2016 TAM?

A. Yes. In the 2016 TAM, Staff, CUB, and ICNU objected to the DA/RT adjustment. The Commission rejected their arguments and approved the adjustment, concluding that it more accurately reflected the costs of system balancing transactions in the company's NPC forecast.[15]

Q. Did PacifiCorp change its DA/RT adjustment in the 2017 TAM?

A. No, with one exception. In the 2017 TAM, PacifiCorp calculated the adjustment using 48 months of historical data, rather than the 36 months of historical data that was used in the 2016 TAM. Although parties objected generally to the DA/RT adjustment, no party objected to the use of additional historical data to normalize the adjustment. When approving the DA/RT adjustment in the 2017 TAM, the Commission found that "four years of data is sufficient to generate a normalized result[.]"[16]

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[15] *In the Matter of PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015); Order No. 16-482 at 13.
[16] Order No. 16-482 at 13.

Q. How did the Commission address the parties' objections to the DA/RT adjustment in the 2017 TAM?

A. As in the 2016 TAM, the Commission rejected the parties' arguments and affirmed the DA/RT adjustment:

> We reaffirm and uphold our decision in Order No. 15-394 approving PacifiCorp's system balancing adjustment. The DA/RT adjustment—while not perfect—reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs. . . No persuasive evidence was offered to convince us that our decision last year was in error.[17]

Although the Commission affirmed the DA/RT adjustment in the 2017 TAM, it also directed the parties to meet informally to examine the adjustment in detail to provide an opportunity to discuss potential alternative modeling approaches.[18]

Q. Did PacifiCorp and the parties meet informally to examine the DA/RT adjustment following the 2017 TAM?

A. Yes. The parties met several times before the filing of the 2018 TAM and discussed the mechanics of the DA/RT adjustment and the parties' specific concerns over how the adjustment is calculated and whether it is necessary. In response to parties' concerns, the Company also provided detailed analysis describing the sensitivity of the DA/RT adjustment to various scenarios suggested by the parties, including abnormal weather, thermal outages, and hydro conditions.

Q. Did the company agree to any modifications to the DA/RT adjustment as a result of the workshops that followed the 2017 TAM?

A. Yes. To address concerns over the use of historical data to calculate the adjustment,

[17] *Id.* at 13.
[18] *Id.* at 14.

PacifiCorp agreed to use 60 months of historical data to calculate the adjustment in the 2018 TAM. As discussed above, the 2016 TAM used 36 months of historical data, and the 2017 TAM used 48 months of historical data for the adjustment.

Q. Did parties again object to the DA/RT adjustment in the 2018 TAM?

A. Yes. ICNU and Staff continued to argue for a reduction in the adjustment. ICNU recommended modifying the adjustment to include only data from after the company joined the EIM and recommended expanding the adjustment to account for transactions that are greater than seven days in advance.[19] Staff recommended modifying the price component to correlate market price and system load and eliminating the volume component.[20] Staff also recommended that the validity of the adjustment should be revisited once the model validation process has concluded. CUB recommended excluding certain historical years from the data set used to calculate the adjustment.[21]

Q. Did the Commission require any modifications to the DA/RT adjustment?

A. Yes. The Commission modified the adjustment to "use only post-EIM years to calculate the adjustment."[22] The Commission was persuaded that future DA/RT costs would "trend closer to post-EIM years, compared to the pre-EIM years of 2011 to 2014."[23] The Commission also observed that its modification largely addressed the concern raised by Staff that the historical data was volatile.[24]

[19] Order No. 17-444 at 6.
[20] *Id.*
[21] *Id.*
[22] Order No. 17-444 at 8.
[23] *Id.*
[24] *Id.*

Q. Did the Commission provide any guidance for the calculation of the DA/RT adjustment in the 2019 TAM?

A. Yes. The Commission directed "PacifiCorp to use post-EIM years for DA/RT . . . as a starting place for the 2019 TAM."[25] The Commission also "want[s] parties and the company to be open to DA/RT refinements that may come out of the model validation process" and therefore did "not reach the parties other proposed DA/RT adjustments."[26] The Commission concluded that it "will continue to evaluate parties' arguments on whether the adjustment accurately represents the company's system balancing costs."[27]

Q. Did the model validation process discussed above confirm the accuracy of the DA/RT adjustment?

A. Yes. In the model validation process, the total company NPC derived from the backcast study is 0.03 percent higher than actual NPC in 2016. It affirmed that the DA/RT adjustment is a legitimate adjustment to the GRID model to accurately forecast NPC.

Q. What is the impact of the DA/RT adjustment to the 2019 TAM, as compared to the 2018 TAM?

A. The DA/RT adjustment in the 2019 TAM is approximately $2.25 million (total-company) lower than the DA/RT adjustment approved by the Commission in the 2018 TAM.

[25] Order No. 17-444 at 9.
[26] *Id.*
[27] *Id.*

Long-term Coal Contract Impact on Dispatch Modeling

Q. How do long-term coal contract provisions impact dispatch decisions in GRID, commitment decisions, and long-term system modeling decision?

A. PacifiCorp's coal contracts inform the coal costs used in the TAM and are an input to the GRID model. GRID uses two pricing tiers for its thermal resources—a dispatch tier and a costing tier.

Q. Please describe the dispatch tier.

A. The dispatch tier reflects that incremental coal price and is used by GRID, along with resource attributes and heat rates, to determine thermal plant dispatch. The company calculates the incremental coal price of contract coal based on the terms of the contract, which may include minimum take requirements and associated liquidated damages. For PacifiCorp-owned mines, the incremental coal price is determined by the operating cost required to produce the next ton of coal.

Q. Please describe the costing tier.

A. The costing tier reflects the average cost of the total coal tonnage in the forecast period and is applied to the coal volumes as determined by GRID, and are reported in the NPC results as total coal fuel burn expense.

Coal Plant Variable O&M

Q. Please describe the issue related to modeling coal plant variable O&M in the TAM.

A. In the 2018 TAM, several parties expressed interest in accounting for variable O&M expenses when determining the dispatch of the company's thermal resources. During the workshops that followed the 2018 TAM, PacifiCorp proposed including variable

O&M expenses in the incremental coal price used in GRID to make dispatch decisions (as discussed above).

Q. Are variable O&M expenses included in the rates established in the TAM?

A. No. Variable O&M expenses are reflected in base rates established in general rate cases. Although the company agrees to model variable O&M expenses in the TAM, those expenses themselves will not be reset in the TAM. The variable O&M expenses will be used to determine coal-plant dispatch only.

Q. What variable O&M expenses will be included in the incremental coal price?

A. Coal-fueled variable O&M costs include primarily chemicals and ash handling expenses.

Q. What is the impact of the inclusion of O&M expense in the incremental coal price used to determine coal plant dispatch in the 2019 TAM, as compared to the 2018 TAM?

A. The inclusion of O&M cost in the incremental coal price in the 2019 TAM resulted in coal plant dispatch that increased total company NPC by approximately $1.8 million versus without the inclusion.

Coal Plant Economic Cycling Modeling

Q. Please describe the issue related to coal plant economic cycling modeling.

A. In the 2018 TAM, Staff proposed an adjustment intended to model the economic shutdown of coal plants, which had occurred in limited historical circumstances based on unusual market conditions in 2016 and 2017. The Commission rejected Staff's adjustment but expressed an interest in understanding how PacifiCorp's operations may be changing under evolving market conditions.[28]

Q. Does the company propose to model economic cycling of coal plants in the 2019 TAM?

A. Yes. In response to the Commission's interest, PacifiCorp proposes modeling economic shutdowns for coal plants that are majority-owned by the company, that are not participating in the EIM, and that are not under operational constraints that would preclude an economic shutdown.

Q. How will the company model economic cycling?

A. The cycling period (*i.e.*, when a coal unit could be shut down for economic reasons) will run from February 1 to May 31, which corresponds to the spring run-off period when loads are generally lower, weather is typically mild, market prices are lower, and solar imports from California are increasing.

Under the company's proposal, the "must run" setting in GRID for the eligible coal plants is removed and these plants are dispatched based on economics during the cycling period. The eligible coal plants incorporate the minimum up time, minimum downtime and startup costs as part of the economic dispatch parameters. The number of startups during the entire cycling period is limited to no more than four.

Q. What are the results of the company's economic cycling modeling and how do the results compare to actual coal operation experiences?

A. Confidential Table 4 below compares the actual coal plant economic cycling in days from the year 2015, 2016, 2017, and forecasted 2019. The table shows the 2019

[28] Order No. 17-444 at 11.

forecast results in coal plants being offline for 7,636 hours or approximately 2.7 million MWh which is higher than the total economic cycling hours in 2016 and 2017. Based on the market price forecast and market condition forecast for 2019, PacifiCorp believes the coal economic cycling forecast for 2019 will reasonably capture possible economic cycling of coal units during 2019.

Confidential Table 4

[redacted]

Q. What is the impact of the economic cycling to the 2019 TAM, as compared to the 2018 TAM?

A. The economic cycling of coal plants reduced NPC by $0.7 million on a total company basis from the 2018 TAM.

Other Modeling Changes to Improve NPC Forecast Accuracy

Q. Did PacifiCorp make any changes to improve the accuracy of its NPC modeling since the 2018 TAM?

A. Yes. PacifiCorp made three modifications to the GRID inputs to improve the accuracy of forecast NPC, including changes to reflect:

- Regulating reserve requirement based on Flexible Reserve Study in 2017 IRP;
- Actual capacity factor for owned wind plants and purchased wind plants;
- Pioneer Wind QF hourly shape based on location correlation method.

Details supporting each modeling change are provided below.

Q. Why is PacifiCorp proposing changes to NPC modeling in this case?

A. In previous cases, the Commission has encouraged improvements to NPC modeling to improve forecast accuracy. PacifiCorp's proposed modeling changes capture costs and benefits that have not been recognized in the company's past NPC forecasts.

Q. Did PacifiCorp provide advance notice to the parties regarding the modeling changes proposed in this case?

A. Yes. In compliance with the TAM Guidelines, PacifiCorp provided notice of substantial changes to the company's modeling of NPC in the 2019 TAM. This notice was provided on March 1, 2018, which was supplemented on March 27, 2018.

Regulating Reserve Requirement

Q. How did PacifiCorp update its regulating reserve requirement modeling?

A. The company's regulating reserve requirements are now based on the 2017 Flexible Reserve Study (2017 FRS) that was included as part of the development of the 2017 Integrated Resource Plan.

Q. How has the modeling of regulating reserve requirement changed as a result of the 2017 FRS?

A. There are several modeling changes compared with previous TAMs:

- The regulating reserve requirement is a function of a specific value that is fixed in all hours and a variable regulation reserve requirement that is based on the change in the resource balance from hour to hour.
- The regulating reserve requirement varies when wind and solar generation changes. The load and non-variable energy resource (VER) variables have fixed amount of regulation reserve requirements. VERs refer to variable energy

resources, which: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.

- A unit can be allocated reserves up to the lesser of its 30-minute ramp rate and the difference between its minimum and maximum operating levels. If a unit is allocated reserves, the allocated capacity is subtracted from the unit's maximum operating level, resulting in a reduced maximum dispatch level.
- The inter-hour wind integration, solar integration and load integration cost changes are summarized as follows:

	Integration Cost ($/MWh)	
	2018 TAM 2014 WIS	2019 TAM 2017 FRS
Load	0.01	0.10
Wind	0.75	0.16
Solar-Fixed	0.80	0.16
Solar-Tracking	0.80	0.16

For additional details, please refer to PacifiCorp's 2015 IRP Volume II, Appendix H and 2017 IRP Volume II, Appendix F.

Q. Does modeling reserves on an hourly basis impact the forecast NPC in GRID?

A. Yes. This change decreases NPC by approximately $3.2 million due to the higher amount of reserve capacity of thermal plants, resulting in savings as a result of more expensive thermal holding more reserves during uneconomic hours and releasing lower cost thermal units to serve the load. In addition, lower integration costs of variable resources on the system decreases NPC.

Actual Capacity Factor for Owned Wind Plants and Purchased Wind Plants

Q. Please describe the adjustment made to the forecast capacity factor for owned wind plants and purchase wind plants.

A. Previously, the generation from PacifiCorp's owned wind plants was based on long-range forecasts provided to the company by the project owners. Wind PPA generation is based on 48-month historical generation, which was approved by the Commission in 2016 TAM (UE 296). In this 2019 TAM, PacifiCorp proposes to calculate the annual capacity factor using a cumulative average methodology for any wind plants with a history of historical generation longer than four years. For those projects with less than four years of history, the project owner's forecast is used for the period until the actual results become available.

Actual wind generation at these facilities has varied somewhat from those forecasts, causing PacifiCorp to incur higher or lower power expenses. To better align forecasted NPC with actual results, the company modeled the forecasted wind generation for each of wind plant to match the levels in the cumulative historical period. This change brings the modeling of wind plants in line with the historical actuals, which will better reflect reasonable level of generation for the future period.

Q. What is the impact of using the cumulative historical generation rather than the project owners' forecast?

A. In this case, reflecting the generation output as described above increases NPC approximately $4.6 million.

Pioneer Wind QF Hourly Shape based on Location Correlation Method

Q. Please describe this update.

A. PacifiCorp's proposed Pioneer Wind QF hourly shape uses a dynamic hourly shape that is more representative of actual wind output. The dynamic hourly shape is based on a blend of two wind resources in nearby locations in eastern Wyoming, Top of the World Wind and Three Buttes Wind. The blend is weighted based on the relative distance of the two wind plants to Pioneer Wind. The previously used method is based on a long range forecast from the project developer.

Q. What is the impact of this change?

A. In this case, with the updated hourly shape of Pioneer Wind QF as described above increases NPC approximately $0.5 million.

EIM Costs and Benefits

Q. Has the EIM continued to provide customer benefits?

A. Yes. The company has participated in the EIM since 2014, and has included EIM benefits in the 2015, 2016, 2017, and 2018 TAMs. As set forth in Table 5 below, in each year the benefits increased as regional participation in the market continued to grow. The 2019 TAM reflects increased utility participation in the EIM and still increasing benefits.

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

A. Consistent with its past modeling of EIM benefits, PacifiCorp's 2019 NPC forecast from GRID includes an adjustment to reflect incremental EIM benefits from inter-regional dispatch (*i.e.*, exports and imports between EIM participants) and reduced flexibility reserves. As shown in Table 5, the 2019 TAM includes approximately

$29.3 million of EIM benefits on a total-company basis as a reduction to the NPC forecast.

Table 5

$ millions	2015 TAM	2016 TAM	2017 TAM	2018 TAM	2019 TAM
Inter-regional dispatch		$8.4	$17.5	$37.2	$29.2
Flexibility Reserves		$1.7	$4.1	$3.1	$0.1
Test-period EIM benefits	**$6.7**	**$10.1**	**$21.6**	**$40.3**	**$29.3**

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

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the CAISO balancing authority areas (BAAs). Through the EIM, the company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaces the company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM benefits customers by reducing NPC, with relatively low initial start-up and ongoing operation costs.

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

A. Participation in the EIM reduces the company's actual NPC in three ways. First, the EIM optimizes the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model (i.e., intra-regional benefits). Second, the EIM facilitates transactions between CAISO, PacifiCorp, and other EIM participants on a five- and 15-minute basis (*i.e.*, inter-regional transfer benefits). Third, the EIM reduces the amount of flexible generating capacity required to be held in reserve by PacifiCorp due to the collective reduction of reserves for the larger and more diversified EIM footprint (*i.e.*, flexibility reserve savings). Benefits realized for the last two categories are highly dependent on the amount of transfer capacity between EIM participants that is made available for the EIM.

Q. Do each of the three benefits identified above result in a reduction to the NPC forecast?

A. No. As the Commission found in the 2017 TAM, the GRID model NPC forecast already reflects the optimized (*i.e.*, lowest cost) dispatch of PacifiCorp's generating resources within its two BAAs, so there are no additional benefits from EIM optimized dispatch (*i.e.*, intra-regional and within-hour dispatch benefits).[29] The other two NPC benefits—inter-regional transactions and reduced flexibility reserves—do produce NPC savings relative to the optimized GRID NPC forecast.

Q. Do the EIM benefits in the 2019 TAM account for new EIM participants?

A. Yes. The 2018 TAM included an adjustment to estimate the impact of Idaho Power Company's (IPC) expected entry into the EIM in April 2018. The 2019 TAM will also include a full year of benefits due to the participation of NV Energy (NVE), Arizona Public Service (APS), Puget Sound Energy (PSE), Portland General Electric (PGE), and Idaho Power Company (IPC).

Q. How did the company forecast the benefit associated with reduced flexibility reserves?

A. Using the same methodology as the 2016, 2017, and 2018 TAMs, PacifiCorp reduced the regulating reserve requirement modeled in GRID by roughly 106 MW to account

[29] Order No. 16-482 at 16.

for the company's share of the reserve benefit based on the diversified footprint of the EIM. The methodologies for determining the reduction in reserves associated with the participation of CAISO, NVE, APS, PSE, PGE, and IPC in the EIM are unchanged from the 2018 TAM. The overall reduction in the company's reserve requirement from its participation in EIM decreases NPC by approximately $0.1 million on a total-company basis.

Q. How did the company calculate the EIM benefits resulting from inter-regional transfers?

A. The inter-regional transfers benefit reflects the benefit received by PacifiCorp when it economically transfers energy to the EIM and when it imports energy from the EIM that allows it to displace a more expensive resource.

Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the company's calculation of EIM benefits is the marginal cost to produce an additional megawatt-hour at a given resource. The company's production costs used to calculate EIM benefits are equal to the resource bids submitted to the EIM.

The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.

Q. In the 2018 TAM, did the parties dispute the methodology used to determine the inter-regional transfers benefit?

A. Yes. Staff argued that the company's forecast was too low because it relied on historical data that was too old and did not reflect a reasonable growth rate consistent with the historical growth in inter-regional benefits.[30]

Q. In response to Staff's concerns, did PacifiCorp modify how it calculated inter-regional EIM benefits in the 2018 TAM?

A. Yes. The company relied on the most recent six months of validated EIM data to account for operational changes at PacifiCorp's coal plants that were expected to increase interregional benefits in 2018. To account for growth in EIM benefits, PacifiCorp's forecast also more heavily weighted the most recent data and included an additional adjustment to account for new market participants and the impact of California's over-supply conditions.

Q. How did the Commission resolve the company's modeling of EIM inter-regional transfer benefits?

A. The Commission rejected the parties' adjustments and found that PacifiCorp's calculation was reasonable.[31] The Commission also found that PacifiCorp appropriately accounted for transmission constraints in its modeling.[32]

Q. Has the company changed the methodology used to calculate the inter-regional EIM benefits in the 2019 TAM from the methodology approved in the 2018 TAM?

A. Yes. To better account for the increase of EIM participants, PacifiCorp proposes an enhancement to the calculation of inter-regional EIM benefits. Using EIM benefits by month, a linear trend based on actual EIM benefits beginning in December 2015 was extrapolated forward and an estimate for 2019 benefits was produced. This date

[30] Order No. 17-444 at 15.
[31] Order No. 17-444 at 15-16.
[32] *Id.* at 17.

corresponds with the entry of NV Energy into the EIM. Before this date, PacifiCorp and the CAISO were the only participants in the EIM, and the benefits reflected the scarcity of available transmission capacity as well as the operations learning curve prevalent during these initial months. The time period used to form the extrapolation includes the entry of NVE in December 2015, APS and PSE in October 2016 and PGE in October 2017. Given that new participants are scheduled to enter the EIM in 2018 and 2019, it is reasonable to proxy the future growth of these new participants based upon this historical data set.

Q. Please describe the EIM-related costs included in the 2019 TAM.

A. Consistent with the 2015, 2016, 2017, and 2018 TAMs, the company includes EIM-related costs in the 2019 TAM. In the 2019 TAM, EIM-related costs are $1.3 million. These costs consist of the return on net rate base from the capital investment required to participate in the EIM, depreciation expense, and ongoing O&M expenses and transaction fees. A summary of the various cost components is provided as Exhibit PAC/105.

QF Forecast

Q. Has PacifiCorp modified how it forecasts QF costs in the 2019 TAM?

A. Yes. As discussed above, the QF costs included in this case were calculated using a CDR for new projects, consistent with the CDR approved by the Commission in Order No. 17-444.[33]

Q. How did PacifiCorp calculate the CDR?

A. As required by the 2018 TAM Order, the company used a three-year rolling average

[33] Order No. 17-444 at 17.

of delays to calculate the CDR, which was then weighted by nameplate capacity and applied to the commercial online dates (CODs) of the QFs forecast to come online in 2019.[34]

REC Transfers

Q. Did the company conduct a workshop on REC transfers, as required by the Commission?

A. Yes. PacifiCorp, Staff, Calpine Energy Solutions (Calpine), CUB, and ICNU met on February 5, 2018. As a result of that meeting, the parties have agreed on a proposal to transfer RECs from PacifiCorp to an electricity service supplier (ESS) to account for the migration of direct access load. The agreement is summarized below:

- Following election of direct access, PacifiCorp will transfer RECs on an annual basis to a direct access consumer's ESS.
- RECs will be transferred to a WREGIS account identified by the direct access consumer's ESS.
- Transfers will begin following the first year of direct access, to meet the ESS's renewable portfolio standard (RPS) compliance obligation.
- Based on the prior year compliance obligation, a transfer of Oregon RPS-eligible RECs would take place by May 1 of each year.
- For one- and three-year direct access consumers, the RECs transferred will be based on the prior year's actual load for that consumer.
- For the 5-year/permanent opt-out direct access consumer, the RECs transferred will be based on the following schedule:

[34] Order No. 17-444 at 17.

Period	REC Transfer Amount Calculation
Years 1-5	Compliance obligation is based on the direct access consumer’s actual load.
Years 6-10	Compliance obligation is based on the direct access consumer’s average load over years 1-5 (to align with the transition adjustment and opt-out charge paid by the direct access consumer).

- The specific RECs transferred would be from RPS-eligible resources, at PacifiCorp’s discretion, and may vary from year to year.
- At least 80 percent of the transferred RECs will be RECs that, before the transfer, were considered bundled. PacifiCorp makes no representation and does not warranty that after the transfer any of the RECs transferred to the ESS’s WREGIS account qualify as bundled RECs for the purposes of RPS compliance requirements.
- PacifiCorp is not responsible for the retirement of RECs or claims made about the RECs on behalf of the direct access consumer or ESS, or any RPS compliance of the direct access consumer or ESS.

Consumer Opt-Out Charge

Q. What is the Consumer Opt-Out Charge?

A. The Consumer Opt-Out Charge is a transition adjustment applicable to the company’s five-year direct access program and is intended to recover transition costs incurred during years six through 10 following the departure of the direct access load. The Commission approved the Consumer Opt-Out Chare in docket UE 267, after finding that PacifiCorp will experience transition costs for 10 years and approved the consumer opt-out charge to recover the company’s fixed generation costs in years six through 10.[35] The Commission affirmed the Consumer Opt-Out Charge in the 2016, 2017, and 2018 TAMs.[36]

Q. How does the Consumer Opt-Out Charge operate together with Schedule 200, the rate schedule that collects fixed generation costs?

A. In the first five years after the direct access customer elects to leave, the customer pays the actual Schedule 200 costs, as those costs change during that five-year period. If PacifiCorp adds incremental generation during those five years and those costs flow into Schedule 200, the direct access customer pays those costs.

The Consumer Opt-Out Charge accounts for forecast Schedule 200 costs for years six through 10. To calculate the Consumer Opt-Out Charge, PacifiCorp first takes the Schedule 200 costs in effect at the time the customer departs and escalates those costs for five years, using an inflation escalator. (The departing customer does not pay these escalated Schedule 200 costs for years one through five because the customer is paying the actual Schedule 200 costs for the first five years).

PacifiCorp takes the escalated Schedule 200 cost for year five, and escalates that cost through year 10, using an inflation escalator, to develop a forecast of Schedule 200 costs for years six through 10. The Consumer Opt-Out Charge is then calculated by taking the forecast Schedule 200 costs and reducing them back to calculate a levelized payment made in years one through five. Together, through the payment of Schedule 200 and the Consumer Opt-Out Charge, departing customers

[35] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6-7 (Feb. 24, 2016).
[36] Order No. 15-394 at 12; Order No. 16-482 at 23; Order No. 17-444 at 20.

pay PacifiCorp's fixed generation costs for 10 years (offset by the value of freed-up energy).

Q. Why does PacifiCorp use an inflation escalator to forecast Schedule 200 costs for years six through 10?

A. The inflation escalator accounts for the fact that fixed generation costs reflected in Schedule 200 tend to increase over time, even without incremental generation. Although individual elements of fixed generation costs may decrease (*e.g.*, depreciation expense will generally decrease without incremental generation assets), the net fixed generation costs historically increase. Using an inflation escalator conservatively holds the fixed generation costs constant in real terms. The use of an inflation escalator in the Consumer Opt-Out Charge in years six through 10 is not intended to account for new generation, just as the inflation adjustment in years one through five is not intended to account for new generation.

Q. Has the Commission found that the use of an inflation escalator does not account for incremental generation?

A. Yes. In the 2016 TAM, the Commission affirmed the Consumer Opt-Out Charge after concluding that "incremental generation is not added after year five."[37] In its brief on appeal of the 2016 TAM order, the Commission further explained that "PacifiCorp introduced evidence showing that its consumer opt-out charge includes fixed generation costs only, not new generation investment made by the company six to ten years after a customer opts-out of utility-provided service."[38] Specifically, the

[37] Order No. 15-394 at 12.
[38] *Noble Americas Energy Solutions LLC v. Public Utility Commission of Oregon*, Appellate Court No. A161359, Respondent Public Utility Commission of Oregon's Answering Brief at 6 (Nov. 1, 2016).

Commission relied on evidence that the "consumer opt-out charge includes 'many other factors besides depreciation expense and return of rate base.'"[39] The Commission concluded that "testimony from PacifiCorp's witnesses established that (1) the consumer opt-out charge includes fixed generation costs only; and (2) an inflation-adjusted opt-out charge is a conservative assumption because other factors and charges subsume any depreciation effect, causing the overall rate to increase over time."[40]

Q. Did the Commission address the inclusion of incremental generation investment in the Consumer Opt-Out Charge in the 2017 TAM?

A. Yes. In the 2017 TAM, the Commission again approved the Consumer Opt-Out Charge, finding that it "includes other costs that escalate over time and more than offset the impact of accumulated depreciation."[41]

Q. How did the Commission address the Consumer Opt-Out Charge in the 2018 TAM?

A. The Commission again approved the Consumer Opt-Out Charge, including its use of an inflation escalator. But the Commission also expressed a concern that PacifiCorp had presented a new argument that "incremental generation *should* be allowed in the year six through 10 forecast."[42]

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[39] *Noble Americas Energy Solutions LLC v. Public Utility Commission of Oregon*, Appellate Court No. A161359, Respondent Public Utility Commission of Oregon's Answering Brief at 6-7 (Nov. 1, 2016).
[40] *Noble Americas Energy Solutions LLC v. Public Utility Commission of Oregon*, Appellate Court No. A161359, Respondent Public Utility Commission of Oregon's Answering Brief at 20 (Nov. 1, 2016). (internal citations omitted).
[41] Order No. 16-482 at 23.
[42] Order No. 17-444 at 20 (emphasis added).

Q. Did PacifiCorp argue that the Consumer Opt-Out Charge should include incremental generation investments?

A. No. But the company acknowledges that the record in the 2018 TAM may have been unclear on this point, in part, because Calpine repeatedly mischaracterized the company's position.[43] To be clear, PacifiCorp's position in the 2018 TAM was that the Consumer Opt-Out Charge *could* legally include incremental generation (a position shared by the Commission[44]), but that the use of the inflation adjustment did not include incremental generation.[45]

In response to Calpine's mischaracterization of the company's position, PacifiCorp's reply brief clarified that: "PacifiCorp has consistently argued that the consumer opt-out charge is not intended to account for incremental generation investments after year five because it is held constant in real terms."[46] The reply brief continued: "PacifiCorp has also argued that there is no legal barrier to including incremental generation investment after year five, even though that is not how the consumer opt-out charge is currently calculated."[47] By recommending that the Consumer Opt-Out Charge continue to rely on an inflation adjustment *that does not*

[43] *See, e.g.*, Docket No. UE 323, Calpine Energy Solutions, LLC's Response Brief at 19.
[44] In its briefing before the Oregon Court of Appeals on Calpine's appeal of Order No. 15-394, the Commission argued that "even if [the Consumer Opt-Out Charge included incremental generation investments] (which . . . it does not), the statutory provisions cited by [Calpine] do not expressly prohibit a utility from doing so." *Noble Americas Energy Solutions LLC v. Public Utility Commission of Oregon*, Appellate Court No. A161359, Respondent Public Utility Commission of Oregon's Answering Brief at 15 (Nov. 1, 2016).
[45] *See* Docket No. UE 323, PAC/400, Wilding/59 ("The use of an inflation escalator in the Consumer Opt-Out Charge in years one through five is not intended to account for new generation, <u>just as the inflation adjustment in years six through 10 is not intended to account for new generation</u>.") (emphasis added); *see also* Docket No. UE 307, PacifiCorp's Reply Brief at 39 ("Noble Solutions claims that PacifiCorp has changed its position and now agrees that the consumer opt-out charge accounts for new generation investment in years six through 10. This is untrue. <u>The Company's position here has not changed—the consumer opt-out charge can legally account for new generation investment, but does not actually do so</u>.") (emphasis added).
[46] Docket No. UE 323, PacifiCorp's Reply Brief at 28.
[47] Docket No. UE 323, PacifiCorp's Reply Brief at 28.

account for incremental generation, PacifiCorp was not arguing that incremental generation *should* be included in the calculation of the Consumer Opt-Out Charge.

Q. Did the Commission provide additional guidance on the calculation of the Consumer Opt-Out Charge in the 2018 TAM?

A. Yes. In Order No. 17-444, the Commission described three criteria that apply to the Consumer Opt-Out Charge.[48] First, the company can use a modest inflation adjuster to forecast year six through 10 costs. Second, the company should not include any new incremental generation in the years six through 10-forecast. Third, the company should account for depreciation. The Commission directed PacifiCorp to explain in the 2019 TAM how the Consumer Opt-Out Charge meets each of these criteria.

Q. Does the Consumer Opt-Out Charge approved by the Commission in docket UE 267, and affirmed in the 2016, 2017, and 2018 TAMs satisfy these three criteria?

A. Yes. First, the company relies on a conservative inflation adjustment to forecast fixed generation costs for years six through 10.

Second, the inflation adjustment does not account for incremental generation investments. This has been PacifiCorp's position since the Consumer Opt-Out Charge was first approved and the Commission specifically made this finding in the 2016 and 2017 TAMs, as discussed above.

Third, depreciation expense is accounted for by the conservative use of an inflation escalator. As noted above, the Commission made this point to the Court of Appeals: "an inflation-adjusted opt-out charge is a conservative assumption because other factors and charges subsume any depreciation effect, causing the overall rate to

[48] Order No. 17-444 at 21.

increase over time."[49] The Commission also made this finding in the 2017 TAM: "the consumer opt-out charge includes other costs that escalate over time and more than offset the impact of accumulated depreciation."[50] And the record in the 2018 TAM provided additional evidence that even without incremental generation included in the forecast for years six through 10, PacifiCorp's fixed generation costs have historically increased at a rate greater than inflation.[51]

Q. Since the Consumer Opt-Out Charge previously approved meets the Commission's criteria, has the company proposed a modification to how it is calculated?

A. No. In response to the Commission's guidance in the 2018 TAM, the company calculated an inflator based on ten years of historical fixed generation costs. For the years 2006 through 2015 fixed generation costs increased at an average annual rate of 8.04 percent, and for the years 2007 through 2016 fixed generation costs increased at an average annual rate of average 4.46 percent. Notably, depreciation is accounted for in both scenarios. After removing incremental generation and still accounting for depreciation, historical fixed generation costs increased at an average annual rate of 5.65 percent and 2.76 percent for years 2006 through 2015 and 2007 through 2016, respectively. Exhibit PAC/110 provides the details of this analysis.

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[49] *Noble Americas Energy Solutions LLC v. Public Utility Commission of Oregon*, Appellate Court No. A161359, Respondent Public Utility Commission of Oregon's Answering Brief at 20 (Nov. 1, 2016). (internal citations omitted).
[50] Order No. 16-482 at 23.
[51] *See* Docket No. UE 323, PacifiCorp's Opening Brief at 47-49 ("even if major capital additions are removed, Calpine's analysis shows that fixed generation costs still increase—by 64 percent from 2006 to 2015, 19 percent from 2007 to 2015, 2 percent from 2008 to 2015, and 16 percent 2009 to 2015.") (internal citations omitted).

Based on this analysis, it is reasonable to use inflation as the inflator for years six through tem in place of calculating a new inflator each year. As seen above, a new inflator each year could produce an inflator higher than inflation.

Q. Why after accounting for depreciation and removing incremental generation do the fixed generation costs still increase?

A. Fixed generation costs increase for reasons other than adding incremental generation. Calpine's depreciation rate of 8.38 percent cited in the 2018 TAM order assumes that incremental generation is the only reason fixed generation costs could increase and absent incremental generation depreciation would cause the fixed generation costs to decrease. This is an assumption both PacifiCorp and the Commission have rebutted.[52]

COMPLIANCE WITH TAM GUIDELINES

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

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

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

A. Yes.

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

A. Yes. Exhibit PAC/111 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

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[52] *See Noble Americas Energy Solutions LLC v. Public Utility Commission of Oregon*, Appellate Court No. A161359, Respondent Public Utility Commission of Oregon's Answering Brief at 14 (Nov. 1, 2016).

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 provided the NPC report workbook and the GRID project report.

Q. Did PacifiCorp provide a step-log of model and input changes describing changes to the company's modeling or inputs that are not considered a standard annual update, consistent with the agreement that followed the 2017 TAM?

A. Yes. The company has provided the step-log as Exhibit PAC/108.

Q. Did the company provide pre-filing notice to the parties of modeling and input changes in the 2019 TAM, consistent with the agreement that followed the 2017 TAM?

A. Yes. PacifiCorp's notice of substantial changes to the company's modeling of NPC in the 2019 TAM, provided on March 1, 2018, is included as Exhibit PAC/109.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 339
Exhibit PAC/101
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Oregon-Allocated Net Power Costs

March 2018

PacifiCorp
CY 2019 TAM
Initial Filing

			Total Company					Oregon Allocated	
Line no		ACCT.	UE-323 CY 2018 - Final Update	TAM CY 2019 - Initial Filing	Factor	Factors CY 2018	Factors CY 2019	UE-323 CY 2018 - Final Update	TAM CY 2019 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	14,589,272	8,142,702	SG	25.741%	26.725%	3,755,357	2,176,121
3	Existing Firm UPL	447	-	-	SG	25.741%	26.725%	-	-
4	Post-Merger Firm	447	416,976,550	315,490,543	SG	25.741%	26.725%	107,332,001	84,314,241
5	Non-Firm	447	-	-	SE	24.186%	25.322%	-	-
6	**Total Sales for Resale**		431,565,821	323,633,245				111,087,358	86,490,363
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	4,627,573	3,365,936	SG	25.741%	26.725%	1,191,162	899,540
10	Existing Firm Demand UPL	555	23,836,008	2,756,828	SG	25.741%	26.725%	6,135,516	736,757
11	Existing Firm Energy	555	30,516,365	17,869,545	SE	24.186%	25.322%	7,380,840	4,524,997
12	Post-merger Firm	555	635,614,579	609,731,622	SG	25.741%	26.725%	163,610,602	162,949,604
13	Secondary Purchases	555	-	-	SE	24.186%	25.322%	-	-
14	Other Generation Expense	555	7,552,475	7,091,901	SG	25.741%	26.725%	1,944,047	1,895,297
15	**Total Purchased Power**		702,146,999	640,815,832				180,262,168	171,006,195
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	21,359,209	22,380,362	SG	25.741%	26.725%	5,497,975	5,981,109
19	Existing Firm UPL	565	-	-	SG	25.741%	26.725%	-	-
20	Post-merger Firm	565	117,589,895	109,568,290	SG	25.741%	26.725%	30,268,270	29,281,915
21	Non-Firm	565	6,273,914	4,447,418	SE	24.186%	25.322%	1,517,440	1,126,193
22	**Total Wheeling Expense**		145,223,018	136,396,070				37,283,685	36,389,216
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	753,810,234	676,667,893	SE	24.186%	25.322%	182,320,284	171,348,518
26	Fuel Consumed - Coal (Cholla)	501	55,637,424	40,869,237	SE	24.186%	25.322%	13,456,743	10,349,070
27	Fuel Consumed - Gas	501	3,252,700	4,631,939	SE	24.186%	25.322%	786,714	1,172,918
28	Natural Gas Consumed	547	247,372,678	317,504,511	SE	24.186%	25.322%	59,830,783	80,399,747
29	Simple Cycle Comb. Turbines	547	2,439,959	3,718,622	SE	24.186%	25.322%	590,141	941,644
30	Steam from Other Sources	503	5,000,414	4,484,552	SE	24.186%	25.322%	1,209,425	1,135,596
31	**Total Fuel Expense**		1,067,513,408	1,047,876,754				258,194,090	265,347,493
32									
33	**Net Power Cost (Per GRID)**		1,483,317,604	1,501,455,411				364,652,585	386,252,542
34									
35	Oregon Situs NPC Adustments		647,742	645,737	OR	100.000%	100.000%	647,742	645,737
36	**Total NPC Net of Adjustments**		1,483,965,346	1,502,101,148				365,300,327	386,898,278
37									
38	Non-NPC EIM Costs*		4,944,640	3,414,924	SG	25.741%	26.725%	1,272,777	912,632
39	Production Tax Credit (PTC)		(66,634,263)	(22,247,375)	SG	25.741%	26.725%	(17,152,017)	(5,945,568)
40	**Total TAM Net of Adjustments**		1,422,275,724	1,483,268,697				349,421,087	381,865,342
41									
42								Increase Absent Load Change	32,444,255
43									
44			Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-323					$349,421,087	
45			$ Change due to load variance from UE-323 forecast					15,549,436	
46			2019 Recovery of NPC (incl. PTC) in Rates					$364,970,523	
47	*EIM Benefits for the 2019 TAM are reflected in net power costs								
48								**Increase Including Load Change**	**16,894,819**
49									
50								Add Other Revenue Change	(28,433)
51									
52								**Total TAM Increase**	**16,866,386**

Docket No. UE 339
Exhibit PAC/102
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Net Power Costs Report

March 2018

PacifiCorp

ORTAM19 NPC Study CONF

Net Power Cost Analysis

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12 months ended December 2019	01/19-12/19	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	8,142,702	785,666	695,597	622,943	374,193	584,983	629,652	727,938	767,466	727,916	725,603	748,750	751,995
BPA Wind	2,517,365	291,678	292,735	259,019	199,160	186,184	148,808	124,365	95,212	148,653	206,652	218,906	345,994
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	11,310	942	942	942	942	942	942	942	942	942	942	942	942
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	57,700	3,868	3,773	5,279	3,182	3,814	3,897	7,444	7,514	5,873	4,734	3,837	4,484
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	10,729,076	1,082,155	993,048	888,183	577,477	775,923	783,300	860,689	871,135	883,385	937,932	972,435	1,103,416
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	105,879,140	13,908,150	12,663,000	13,908,150	7,639,280	7,754,060	7,477,900	7,172,700	7,311,720	6,779,880	7,311,720	6,918,900	7,033,680
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	105,879,140	13,908,150	12,663,000	13,908,150	7,639,280	7,754,060	7,477,900	7,172,700	7,311,720	6,779,880	7,311,720	6,918,900	7,033,680
System Balancing Sales													
COB	34,002,754	2,796,110	4,048,891	3,829,218	2,512,487	1,479,246	715,534	632,275	3,662,993	4,269,495	2,429,750	3,473,487	4,153,267
Four Corners	56,320,157	5,740,945	4,576,383	4,250,669	3,108,983	3,316,368	3,335,074	4,485,732	6,657,064	4,224,262	6,811,445	5,303,562	4,509,671
Mead	34,227,220	3,613,820	3,284,152	1,740,132	1,390,851	882,971	2,668,185	1,017,405	3,116,675	4,149,474	4,425,798	4,029,860	3,907,897
Mid Columbia	30,298,351	2,515,646	3,310,500	1,939,476	2,070,644	1,931,836	1,356,599	3,049,040	4,594,453	3,314,975	2,554,350	2,103,357	1,557,476
Mona	29,205,600	2,799,642	2,513,791	1,624,973	1,444,675	2,072,598	2,223,920	1,048,731	2,291,228	3,645,245	3,362,712	3,026,055	3,152,029
NOB	1,785,118	-	-	-	-	34,122	273,353	805,131	672,512	-	-	-	-
Palo Verde	21,160,198	773,202	1,039,888	647,318	813,397	1,458,976	2,584,333	2,888,360	1,486,696	2,677,193	1,403,814	2,412,987	2,974,033
Trapped Energy	25,632	14,771	-	-	-	-	47	-	-	-	91	10,558	164
Total System Balancing Sales	207,025,029	18,254,135	18,773,606	14,031,787	11,341,037	11,176,117	13,157,045	13,926,674	22,481,621	22,280,644	20,987,961	20,359,866	20,254,537
Total Special Sales For Resale	323,633,245	33,244,439	32,429,653	28,828,121	19,557,793	19,706,100	21,418,245	21,960,063	30,664,476	29,943,909	29,237,612	28,251,201	28,391,633

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	1,333,753	72,189	78,183	223,650	127,082	138,117	168,086	149,058	134,316	50,679	87,131	-	105,263
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Combine Hills Wind	5,339,846	370,834	450,711	554,541	536,429	476,958	378,009	449,290	372,676	365,670	363,882	435,553	585,296
Deseret Purchase	33,642,497	2,913,573	2,767,166	2,437,749	2,637,026	2,653,293	2,881,038	2,913,573	2,913,573	2,881,038	2,849,859	2,881,038	2,913,573
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,202,451	140,059	124,705	109,926	108,215	125,225	218,161	379,975	352,812	195,916	133,695	125,824	187,938
Gemstate	1,591,536	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Purchase	126,102	10,509	10,509	10,509	10,508	10,509	10,508	10,509	10,509	10,508	10,509	10,508	10,509
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	5,537,810	457,140	469,170	461,150	461,150	461,150	461,150	453,130	457,140	457,140	457,140	469,170	473,180
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Rock River Wind	5,036,786	650,277	507,436	531,495	451,096	285,523	259,869	180,683	196,323	263,228	470,188	597,196	643,473
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,975,176	2,835,822	1,829,093	2,170,520	1,685,228	1,431,425	1,232,333	809,599	969,864	1,228,160	1,663,363	2,373,769	2,746,000
Top of the World Wind	42,601,328	5,696,685	3,788,055	4,423,384	3,491,743	3,031,510	2,543,558	1,783,270	1,973,064	2,426,014	3,541,583	4,694,630	5,207,832
Tri-State Purchase	9,855,155	738,139	718,118	738,139	731,465	738,139	1,002,586	1,008,744	964,331	927,705	738,139	731,465	818,184
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,180,982	754,633	854,277	1,144,142	1,056,094	792,652	825,976	626,255	658,125	763,010	787,585	987,060	931,174
Long Term Firm Purchases Total	165,722,293	17,047,375	14,004,978	15,212,719	13,703,550	12,552,078	12,388,821	11,171,653	11,410,279	11,976,564	13,510,572	15,713,765	17,029,940
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	6,442,511	557,014	570,153	601,036	800,961	847,474	690,358	517,824	300,944	397,603	312,236	359,471	487,438
QF Idaho	8,116,378	622,527	582,381	625,993	651,725	750,729	802,990	755,211	658,241	631,980	663,264	648,437	722,900
QF Oregon	56,805,045	3,414,892	3,610,163	4,587,034	5,597,573	6,050,929	6,015,915	5,978,309	5,638,994	4,897,672	4,158,861	3,291,233	3,563,470
QF Utah	10,621,453	728,410	759,760	902,934	941,534	1,033,104	1,050,609	978,140	971,603	912,896	871,705	769,694	701,063
QF Washington	153,965	-	-	-	5,925	13,958	24,748	33,049	35,353	28,889	12,043	-	-
QF Wyoming	234,402	41,017	22,857	23,501	18,097	16,527	10,304	15,268	14,672	13,623	15,166	21,363	22,007
Biomass One QF	14,499,150	1,183,004	1,312,208	1,281,800	930,978	948,306	916,311	1,573,193	1,272,042	1,331,181	1,269,262	1,253,328	1,227,538
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	520,350	52,119	46,203	57,568	40,323	34,025	32,348	41,957	36,046	32,269	36,475	55,556	55,460
DCFP QF	129,585	2,938	5,861	9,949	8,105	7,378	9,643	19,212	21,386	12,212	18,099	10,338	4,465
Enterprise Solar I QF	12,873,061	631,368	768,323	999,704	1,144,027	1,292,767	1,415,427	1,604,592	1,561,529	1,205,657	979,290	716,774	553,602
Escalante Solar I QF	11,885,226	578,848	693,387	900,246	1,040,269	1,225,941	1,337,472	1,487,002	1,442,003	1,115,634	894,600	653,539	516,286
Escalante Solar II QF	11,188,314	543,880	650,940	848,142	978,334	1,159,066	1,265,434	1,406,168	1,353,210	1,051,554	838,810	611,331	481,444
Escalante Solar III QF	10,769,184	529,084	636,144	822,929	951,408	1,128,464	1,233,873	1,363,046	1,313,279	1,021,869	767,684	560,067	441,338
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,010,835	490,079	786,729	734,769	770,534	481,999	513,121	555,441	606,715	694,524	705,815	830,258	840,853
Foote Creek III Wind QF	1,725,019	215,225	164,434	220,707	146,128	93,667	83,952	83,573	95,956	102,255	163,079	170,801	185,241
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	11,172,391	560,236	626,980	911,546	1,012,795	1,190,836	1,291,668	1,384,113	1,305,652	995,548	828,418	590,383	474,218
Granite Mountain West Solar QF	7,399,865	370,959	415,122	604,742	672,138	789,095	855,017	917,888	863,927	658,597	548,316	390,514	313,550
Iron Springs Solar QF	11,476,221	647,444	675,187	913,548	1,041,922	1,163,831	1,319,018	1,395,515	1,365,657	1,024,881	835,411	587,237	506,569
Kennecott Refinery QF	146,602	-	-	14,025	14,842	22,068	19,033	21,770	22,872	15,074	7,577	4,136	5,205
Kennecott Smelter QF	774,705	-	36,989	45,471	34,398	126,825	78,128	113,606	121,212	62,277	46,918	46,819	62,063
Latigo Wind Park QF	9,675,473	1,011,726	917,570	1,122,669	897,120	860,620	741,775	673,722	572,323	612,790	802,754	709,690	752,715
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	9,038,752	1,435,965	1,039,342	905,290	675,929	531,186	503,288	411,752	441,350	470,801	664,776	893,294	1,065,779
Mountain Wind 2 QF	14,116,304	2,097,857	1,559,484	1,423,133	1,056,311	829,940	902,630	766,315	727,980	779,543	997,468	1,390,405	1,585,240
North Point Wind QF	17,734,925	1,018,801	1,680,715	1,615,499	1,708,914	1,064,088	1,148,194	1,286,474	1,473,688	1,638,118	1,625,817	1,750,440	1,724,176
Oregon Wind Farm QF	12,244,131	709,523	970,553	1,130,141	1,269,199	1,247,696	1,128,535	1,251,043	1,079,720	929,035	717,100	760,120	1,051,466
Pavant II Solar QF	3,767,978	156,261	193,864	313,517	369,766	404,410	389,347	480,732	464,848	365,687	300,073	182,700	146,774
Pioneer Wind Park I QF	10,638,719	1,306,395	925,521	1,181,396	923,071	703,285	656,795	645,444	684,888	460,924	786,035	1,245,038	1,119,928
Power County North Wind QF	5,201,503	396,624	505,059	519,377	494,233	343,866	331,859	345,681	352,432	366,270	469,010	507,273	569,819
Power County South Wind QF	4,685,092	353,847	446,529	476,553	463,547	301,562	298,582	308,502	331,709	328,773	413,876	462,544	499,067
Roseburg Dillard QF	847,140	52,084	50,374	55,420	62,396	64,059	53,628	107,382	110,746	81,064	67,333	69,266	73,388
Sage I Solar QF	115,048	-	-	-	-	-	-	-	-	-	-	38,872	76,177
Sage II Solar QF	115,168	-	-	-	-	-	-	-	-	-	-	38,919	76,249
Sage III Solar QF	97,660	-	-	-	-	-	-	-	-	-	-	32,946	64,714
Spanish Fork Wind 2 QF	2,664,721	210,467	165,516	204,150	151,900	149,459	206,816	282,215	303,999	259,695	242,934	237,941	249,628
Sunnyside QF	29,974,494	2,649,748	2,467,275	2,559,597	1,671,403	2,608,987	2,636,548	2,668,885	2,680,291	2,551,535	2,271,542	2,583,723	2,624,961
Sweetwater Solar QF	7,924,418	264,401	380,791	574,250	700,614	830,287	996,961	1,140,075	1,061,376	825,497	640,515	304,954	204,698
Tesoro QF	591,008	15,706	51,182	81,827	55,841	72,285	35,180	30,362	37,805	48,555	46,890	52,076	63,299
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,638,631	419,988	481,026	633,344	853,592	883,932	929,425	1,079,534	1,038,694	807,761	687,729	449,177	374,429
Utah Pavant Solar QF	4,906,287	181,901	232,694	392,486	433,756	482,222	533,768	641,344	639,623	522,274	395,370	248,363	202,486
Utah Red Hills Solar QF	11,699,113	492,395	626,049	797,079	1,045,639	1,222,505	1,251,567	1,555,578	1,494,375	1,327,953	824,117	594,615	467,242
Qualifying Facilities Total	339,620,828	23,942,733	25,057,366	29,091,370	29,635,245	30,977,381	31,710,268	33,919,917	32,497,141	28,582,470	25,926,365	24,123,629	24,156,943
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(352,568)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)	(29,381)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,037,631	169,803	169,803	169,803	169,803	169,803	169,803	169,803	169,803	169,803	169,803	169,803	169,803
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,685,064	140,422	140,422	140,422	140,422	140,422	140,422	140,422	140,422	140,422	140,422	140,422	140,422
Total Long Term Firm Purchases	507,028,184	41,130,530	39,202,765	44,444,511	43,479,217	43,669,880	44,239,511	45,231,992	44,047,842	40,699,456	39,577,359	39,977,816	41,327,305

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	11,302,100	2,373,250	2,166,600	2,373,250	494,000	494,000	475,000	494,000	513,000	456,000	513,000	475,000	475,000
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	7,218,781	1,794,536	1,341,893	1,259,999	247,676	259,020	313,001	418,959	431,218	306,840	288,808	260,822	296,011
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	18,520,881	4,167,786	3,508,493	3,633,249	741,676	753,020	788,001	912,959	944,218	762,840	801,808	735,822	771,011
System Balancing Purchases													
COB	6,270,674	43,191	343,456	493,469	749,012	443,011	1,164,068	800,410	1,384,718	101,280	93,283	168,308	486,468
Four Corners	9,949,811	626,139	752,467	1,179,125	639,849	359,796	665,776	1,534,039	1,866,203	895,033	786,253	95,270	549,861
Mead	2,381,372	-	123,155	45,373	232,517	22,293	300,724	144,682	949,093	267,067	1,372	141,269	153,828
Mid Columbia	71,904,849	2,971,347	5,278,272	2,319,475	6,543,200	10,039,211	5,739,625	11,838,877	12,700,628	6,042,840	4,444,098	1,432,439	2,554,837
Mona	8,235,248	1,062,456	950,366	1,087,310	585,827	262,866	87,340	571,926	914,862	401,745	202,270	864,590	1,243,689
NOB	4,806,098	-	-	-	10,057	45,842	462,065	2,814,674	1,473,459	-	-	-	-
Palo Verde	28,106,955	4,318,563	6,497,654	6,972,654	1,716,810	1,861,141	997,410	1,220,251	491,375	1,262,091	1,319,814	433,070	1,016,121
EIM Imports/Exports	(29,225,436)	(2,333,648)	(2,352,158)	(2,370,668)	(2,389,178)	(2,407,688)	(2,426,198)	(2,444,708)	(2,463,218)	(2,481,728)	(2,500,238)	(2,518,748)	(2,537,258)
Emergency Purchases	345,296	90,836	-	37,720	26,363	12,671	-	37,131	-	139,615	148	812	-
Total System Balancing Purchases	102,774,866	6,778,884	11,593,212	9,764,458	8,114,457	10,639,143	6,990,809	16,517,282	17,317,121	6,627,943	4,347,001	617,010	3,467,545
Total Purchased Power & Net Inter	633,723,931	52,527,200	54,754,470	58,292,217	52,785,350	55,512,043	52,468,321	63,112,234	62,759,180	48,540,238	45,176,167	41,780,648	46,015,860

Wheeling & U. of F. Expense													
Firm Wheeling	134,907,501	11,781,482	11,319,734	11,250,054	11,124,378	10,808,924	11,102,205	11,145,777	10,820,464	10,918,586	11,426,025	11,557,153	11,652,719
C&T EIM Admin fee	1,429,782	123,704	116,049	127,527	122,037	121,246	126,490	125,247	108,962	99,828	123,079	118,018	117,595
ST Firm & Non-Firm	58,787	6,104	7,677	164	443	2,381	1,872	5,111	5,486	4,546	5,254	9,474	10,275
Total Wheeling & U. of F. Expense	136,396,070	11,911,290	11,443,461	11,377,745	11,246,858	10,932,551	11,230,567	11,276,135	10,934,912	11,022,959	11,554,358	11,684,645	11,780,589
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	40,869,237	6,087,789	1,741,449	-	-	2,468,694	4,042,399	4,710,406	4,514,606	4,196,473	4,524,774	4,510,066	4,072,579
Colstrip	15,047,980	834,163	1,279,965	1,433,115	1,355,574	450,309	1,351,109	1,437,585	1,408,146	1,331,824	1,433,403	1,306,330	1,426,457
Craig	26,148,672	1,795,636	2,205,764	2,399,086	2,319,142	2,223,529	2,377,575	2,365,174	2,403,015	1,701,605	1,659,360	2,365,093	2,333,693
Dave Johnston	57,622,752	4,444,987	4,483,968	4,275,980	4,955,480	4,576,996	5,032,078	5,204,837	5,541,303	4,925,598	4,800,032	4,765,951	4,615,542
Hayden	11,983,975	1,098,596	1,006,138	653,951	707,994	988,129	1,013,623	1,072,868	1,108,856	1,100,414	1,217,459	974,015	1,041,932
Hunter	112,329,411	14,530,411	7,387,415	3,880,567	2,351,225	3,662,671	8,813,023	12,345,764	13,311,832	11,053,628	9,963,454	11,057,883	13,971,539
Huntington	122,536,556	12,657,143	11,705,849	10,178,264	8,145,856	9,055,198	9,173,630	11,489,654	11,066,340	9,598,869	7,653,845	9,841,224	11,970,684
Jim Bridger	228,235,462	24,322,749	20,706,882	19,390,927	13,965,428	15,636,993	15,102,733	22,363,346	22,187,470	16,886,953	18,398,420	18,314,645	20,958,917
Naughton	74,453,541	6,497,511	5,482,998	6,519,532	6,217,540	5,183,977	5,667,355	6,647,286	6,663,058	6,241,588	6,554,548	6,498,150	6,279,996
Wyodak	28,309,545	2,397,929	2,151,017	2,570,943	987,360	2,412,823	2,630,204	2,494,305	2,699,841	2,592,273	2,646,194	2,534,110	2,192,544
Total Coal Fuel Burn Expense	717,537,130	74,666,913	58,151,446	51,302,365	41,005,599	46,659,319	55,203,729	70,131,226	70,904,467	59,629,224	58,851,489	62,167,467	68,863,884
Gas Fuel Burn Expense													
Chehalis	50,276,087	5,051,603	3,893,709	6,013,913	3,954,731	3,521,195	2,291,537	3,836,951	2,592,017	4,638,561	3,914,412	5,594,644	4,972,814
Currant Creek	55,300,940	3,690,075	5,038,019	6,166,446	3,830,885	4,499,202	4,201,611	5,223,148	5,322,014	4,899,531	4,203,208	3,323,054	4,903,747
Gadsby	3,592,948	-	102,584	102,091	144,734	204,413	187,159	918,714	975,016	602,778	-	23,292	332,166
Gadsby CT	2,498,918	102,253	280,468	185,113	249,541	121,599	105,001	452,114	431,261	219,168	89,235	65,852	197,313
Hermiston	25,166,553	2,571,111	2,553,004	2,734,906	1,676,089	35,965	2,102,810	2,151,756	2,049,896	1,917,778	2,244,153	2,636,621	2,492,465
Lake Side 1	65,857,811	4,610,252	5,187,808	5,350,784	5,497,333	4,000,296	5,526,676	5,416,542	6,322,631	6,020,208	5,736,916	6,097,988	6,090,375
Lake Side 2	67,958,585	5,567,693	5,013,952	4,755,048	5,496,434	5,770,096	5,375,607	6,525,640	6,551,782	6,233,733	5,798,879	5,576,604	5,293,118
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	270,651,842	21,592,987	22,069,544	25,308,300	20,849,747	18,152,766	19,790,400	24,524,865	24,244,618	24,531,758	21,986,804	23,318,054	24,281,999
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	20,523,843	1,364,155	1,505,140	2,308,803	1,825,200	1,904,640	1,796,400	1,749,098	1,745,223	1,816,425	1,779,090	1,475,100	1,254,570
Clay Basin Gas Storage	(141,986)	(69,085)	(58,455)	(14,447)	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	34,821,374	2,908,932	2,796,547	2,919,097	2,883,948	2,923,281	2,879,653	2,955,100	2,956,346	2,895,630	2,909,476	2,866,617	2,926,748
Total Gas Fuel Burn Expense	325,855,072	25,796,989	26,312,776	30,521,753	25,558,895	22,980,687	24,466,453	29,229,063	28,946,187	29,243,813	26,675,370	27,659,771	28,463,316
Other Generation													
Blundell	4,484,552	398,172	371,762	399,039	324,677	367,010	329,243	373,454	355,233	365,564	401,273	403,015	396,110
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Dunlap I Wind	-												
Foote Creek I Wind	-												
Glenrock Wind	-												
Glenrock III Wind	-												
Goodnoe Wind	-												
High Plains Wind	-												
Leaning Juniper 1	-												
Marengo I Wind	-												
Marengo II Wind	-												
McFadden Ridge Wind	-												
Rolling Hills Wind	-												
Seven Mile Wind	-												
Seven Mile II Wind	-												

Black Cap Solar													
Integration Charge	7,091,901	630,805	551,597	595,311	558,397	574,462	588,675	647,653	622,574	557,356	558,173	576,721	630,177
Total Other Generation	11,576,453	1,028,976	923,359	994,351	883,074	941,473	917,919	1,021,107	977,807	922,920	959,445	979,735	1,026,287
Net Power Cost	**1,501,455,411**	132,686,929	119,155,858	123,660,311	111,921,984	117,319,973	122,868,744	152,809,701	143,858,077	119,415,246	113,979,218	116,021,066	127,758,304
Net Power Cost/Net System Load	**25.46**	**25.12**	**25.91**	**25.93**	**24.97**	**25.09**	**25.29**	**27.36**	**26.87**	**25.43**	**24.62**	**24.33**	**24.20**

Docket No. UE 339
Exhibit PAC/103
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Update to Other Revenues

March 2018

PacifiCorp
CY 2019 TAM
Other Revenues - Stand Alone TAM Adjustment
Initial Filing

		Total Company					Oregon Allocated	
Line no		UE-323 Final	CY 2019 Initial	Factor	Factors CY 2018	Factors CY 2019	UE-323 Final	CY 2019 Initial
1	Seattle City Light - Stateline Wind Farm	(10,861,266)	(11,086,374)	SG	25.741%	26.725%	(2,795,748)	(2,962,812)
2	Non-company owned Foote Creek	(905,486)	(881,309)	SG	25.741%	26.725%	(241,989)	(235,528)
3	BPA South Idaho Exchange	-	-	SG	25.741%	26.725%	-	-
4	Little Mountain Steam Revenues	-	-	SG	25.741%	26.725%	-	-
5	James River Royalty Offset	-	-	SG	25.741%	26.725%	-	-
6							-	
7	Total Other Revenue	(11,766,752)	(11,967,683)				(3,037,737)	(3,198,340)
8								
9	Decrease (Increase) in Other Revenues Absent Load Change							(160,603)
10								
11	Baseline Other Revenues in Rates						(3,037,737)	
12	$ Change due to load variance from UE 323 CY 2018 forecast						(132,170)	
13	Other Revenues in Rates using 2019 load forecast						(3,169,908)	
14								
15	**Decrease (Increase) in Other Revenues Including Load Change**							**(28,433)**

REDACTED
Docket No. UE 339
Exhibit PAC/104
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Michael G. Wilding

Energy Imbalance Market Benefits

March 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 339
Exhibit PAC/105
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Energy Imbalance Market Costs

March 2018

PacifiCorp
Oregon 2019 TAM
EIM Costs
Initial Filing - March 31, 2018

$ dollars

	CY 2019 EIM Costs 13 Month Average					
	Total Company		Factor	Factors	Oregon Allocated	
	2018 Final	Initial Filing		CY 2019	2018 Final	Initial Filing
Capital Investment	16,439,327	16,407,565	SG	26.725%	4,231,571	4,384,890
ADIT	(2,816,759)	(2,353,724)	SG	26.725%	(725,049)	(629,028)
Depreciation Reserve	(9,372,567)	(11,576,468)	SG	26.725%	(2,412,549)	(3,093,789)
Net Rate Base	4,250,000	2,477,372			1,093,973	662,073
	10.75%	10.75%			10.75%	10.75%
Pre-Tax Return on Rate Base	$ 457,041	$ 266,414	SG	26.725%	$ 117,645	$ 71,199
Operation & Maintenance (Ongoing)	1,884,622	1,934,376	SG	26.725%	485,112	516,958
Depreciation	2,602,977	1,214,134	SG	26.725%	670,020	324,475
Total Revenue Requirement	$ 4,944,640	$ 3,414,924			$ 1,272,777	$ 912,632
CAISO Fee in net power costs	$ 1,372,457	$ 1,429,782	SG	26.725%	353,278	382,107
Total EIM Costs	$ 6,317,098	$ 4,844,707			$ 1,626,055	$ 1,294,739

Docket No. UE 339
Exhibit PAC/106
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Update to Renewable Energy Production Tax Credits

March 2018

PacifiCorp
CY 2019 TAM
Production Tax Credits

Line no	Plant Name	PTC Expiration Date	Total Company CY 2018 Final	Factor	Factors CY 2018	Oregon Allocated CY 2018 Final	Oregon Allocated Revenue Requirement
	PTC Revenue Requirement in UE-323						
1	JC Boyle	11/7/2015	$ -	SG	25.741%	$ -	$ -
2	Blundell Bottoming Cycle KWh	12/1/2017	-	SG	25.741%	-	$ -
3	Glenrock KWh	12/30/2018	(7,949,734)	SG	25.741%	(2,046,304)	$ (3,293,544)
4	Glenrock III KWh	1/16/2019	(2,985,815)	SG	25.741%	(768,565)	$ (1,237,012)
5	Goodnoe KWh	12/17/2017	-	SG	25.741%	-	$ -
6	High Plains Wind	10/14/2019	(7,424,880)	SG	25.741%	(1,911,204)	$ (3,076,099)
7	Leaning Juniper 1 KWh	9/13/2016	-	SG	25.741%	-	$ -
8	Leaning Juniper Indemnity	9/13/2016	-	SG	25.741%	-	$ -
9	Marengo KWh	8/2/2017	-	SG	25.741%	-	$ -
10	Marengo II KWh	6/25/2018	(2,482,279)	SG	25.741%	(638,952)	$ (1,028,399)
11	McFadden Ridge	10/31/2019	(2,065,509)	SG	25.741%	(531,673)	$ (855,732)
12	Rolling Hills KWh	1/16/2019	-	SG	25.741%	-	$ -
13	Seven Mile KWh	12/30/2018	(8,359,081)	SG	25.741%	(2,151,672)	$ (3,463,135)
14	Seven Mile II KWh	12/30/2018	(1,646,541)	SG	25.741%	(423,828)	$ (682,156)
15	Dunlap I Wind KWh	9/29/2020	(8,486,538)	SG	25.741%	(2,184,480)	$ (3,515,940)
16							
17	Total Production Tax Credit		$ (41,400,377)			$ (10,656,679)	$ (17,152,017)
18							
19							
20							
21							
22	**PTC Revenue Requirement CY 2019**						
23			**Total Company**			**Oregon Allocated**	
24	Plant Name	PTC Expiration Date	CY 2019 Initial	Factor	Factors CY 2019	CY 2019 Initial	Revenue Requirement
25	JC Boyle	11/7/2015	-	SG	26.725%	-	-
26	Blundell Bottoming Cycle KWh	12/1/2017	-	SG	26.725%	-	-
27	Glenrock KWh	12/30/2018	-	SG	26.725%	-	-
28	Glenrock III KWh	1/16/2019	(159,739)	SG	26.725%	(42,690)	(56,608)
29	Goodnoe KWh	12/17/2017	-	SG	26.725%	-	-
30	High Plains Wind	10/14/2019	(5,509,610)	SG	26.725%	(1,472,433)	(1,952,481)
31	Leaning Juniper 1 KWh	9/13/2016	-	SG	26.725%	-	-
32	Leaning Juniper Indemnity	9/13/2016	-	SG	26.725%	-	-
33	Marengo KWh	8/2/2017	-	SG	26.725%	-	-
34	Marengo II KWh	6/25/2018	-	SG	26.725%	-	-
35	McFadden Ridge	10/31/2019	(1,775,360)	SG	26.725%	(474,462)	(629,148)
36	Rolling Hills KWh	1/16/2019	-	SG	26.725%	-	-
37	Seven Mile KWh	12/30/2018	-	SG	26.725%	-	-
38	Seven Mile II KWh	12/30/2018	-	SG	26.725%	-	-
39	Dunlap I Wind KWh	9/29/2020	(9,332,793)	SG	26.725%	(2,494,171)	(3,307,331)
40							
41	Total Production Tax Credit		(16,777,501)			(4,483,755)	(5,945,568)
42							
43						**Increase Absent Load Change**	**11,206,449**
44							
45							

PacifiCorp
CY 2018 TAM
Calculation of Production Tax Credits - Stand Alone TAM Adjustment

		Total Company					
		Generation (KWh)		Tax Rate		Tax Credit	
Line no		CY 2018	CY 2019	CY 2018	CY 2019	CY 2018	CY 2019
1	JC Boyle	-	-	$ 0.012	$ 0.012	$ -	$ -
2	Blundell Bottoming Cycle	-	-	$ 0.023	$ 0.024	$ -	$ -
3	Glenrock	331,238,916	-	$ 0.023	$ 0.024	$ 7,618,495	$ -
4	Glenrock III	124,408,961	6,655,772	$ 0.023	$ 0.024	$ 2,861,406	$ 159,739
5	Goodnoe	-	-	$ 0.023	$ 0.024	$ -	$ -
6	High Plains Wind	309,369,981	229,567,082	$ 0.023	$ 0.024	$ 7,115,510	$ 5,509,610
7	Leaning Juniper 1	-	-	$ 0.023	$ 0.024	$ -	$ -
8	Leaning Juniper Indemnity	-	-	$ 0.023	$ 0.024	$ -	$ -
9	Marengo	-	-	$ 0.023	$ 0.024	$ -	$ -
10	Marengo II	103,428,285	-	$ 0.023	$ 0.024	$ 2,378,851	$ -
11	McFadden Ridge	86,062,867	73,973,340	$ 0.023	$ 0.024	$ 1,979,446	$ 1,775,360
12	Rolling Hills	-	-	$ 0.023	$ 0.024	$ -	$ -
13	Seven Mile	348,295,036	-	$ 0.023	$ 0.024	$ 8,010,786	$ -
14	Seven Mile II	68,605,882	-	$ 0.023	$ 0.024	$ 1,577,935	$ -
15	Dunlap I Wind	353,605,732	388,866,367	$ 0.023	$ 0.024	$ 8,132,932	$ 9,332,793
16	Total Production Tax Credit					$ 39,675,360	$ 16,777,501

PacifiCorp
Oregon
Variables

1	**Net to Gross Bump-up Factor**	
2	(From the December 2014 Results JAM)	
3	Operating Revenue	100.000%
4		
5	Operating Deductions	
6	Uncollectible Accounts	0.000%
7	Taxes Other - Franchise Tax	0.000%
8	Taxes Other - Revenue Tax	0.000%
9	Taxes Other - Resource Supplier	0.000%
10	Taxes Other - Gross Receipts	0.000%
11		
12	Sub-Total	100.000%
13		
14	State Income Tax @ 4.54%	4.540%
15		
16	Sub-Total	95.460%
17		
18	Federal Income Tax @ 21.00%	20.047%
19		
20	Net Operating Income	75.413%

Docket No. UE 339
Exhibit PAC/107
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Staff Public Meeting Report on Model Validation Workshop

March 2018

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 3, 2018

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: December 27, 2017

TO: Public Utility Commission

FROM: Lance Kaufman LK

THROUGH: Jason Eisdorfer and John Crider JE JC

SUBJECT: PACIFIC POWER: (Docket No. UE 323) Status Report on Transition Adjustment Mechanism Workshops.

STAFF RECOMMENDATION:

None.

DISCUSSION:

Issue

Through Order No. 17-444, the Commission ordered PacifiCorp to perform a limited model validation analysis (Analysis) prior to the 2019 TAM. The Commission directed parties to meet and discuss the scope and mechanics of such a validation process, and to report back to the Commission on the scope and timeline of the Analysis by the first public meeting in 2018.

Discussion and Analysis

On December 5, 2017 Staff met with PacifiCorp for preliminary discussion regarding the Analysis. On December 18, 2017, Staff met with PacifiCorp, ICNU, and the Oregon Citizen' Utility Board (CUB) (collectively, Parties) to discuss the scope, inputs and parameters of the limited model validation ordered by the Commission. At the workshop, Parties agreed to the following initial set of parameters for the Analysis:

1) Base year is 2016.
2) Base inputs are the final 2016 TAM update inputs.

3) Replace forecast market energy prices with actual hourly prices for each hub with three different scenarios:
    a. POWERDEX Prices;
    b. PacifiCorp actual real time transaction prices; or
    c. Historic Monthly prices shaped using scalers.
4) Replace forecast natural gas prices with actual natural gas prices.
5) Replace forecast load with actual hourly load.
6) Replace forced outage rate and planned outages with actual outages and actual derates.
    a. Run with/without scenarios for economic shutdowns.
7) Replace forecast wind profile with actual wind profile.
8) Replace forecast hydro conditions with actual hydro conditions.
9) Run a sensitivity study with market caps on and off.
10) Use actual generation profile for long term contracts, PPAs and QFs.
11) Option contracts will be optimized by GRID.
12) Run a sensitivity with actual market transactions of duration greater than 7 days.
13) Use actual heat rate curve.
14) The following items will be updated to reflect major changes not captured in TAM:
    a. Wheeling Costs including long term contract changes and
    b. Incremental Coal costs including transport costs.
15) Update Jim Bridger costing tier prices to reflect actual Jim Bridger coal costs.

PacifiCorp indicated that a timeline for the analysis could not be developed until January 2018 and agreed to provide parties with an update and timeline on January 15, 2018. Parties will schedule follow up workshops to discuss timelines and contemplate any proposed changes to the scope, as appropriate.

<u>Conclusion</u>

Parties have made sufficient progress to date towards developing an agreed-upon model validation analysis for PacifiCorp's NPC. This memo is for informational purposes only and therefore Staff has no recommendations on this issue.

PROPOSED COMMISSION MOTION:

None.

Docket No. UE 339
Exhibit PAC/108
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Step Log Change

March 2018

2019 TAM Step Log

ORTAM18			$ 1,483,317,604
	Description	**Detail**	**Impact**
	Routine Updates		18,456,806
Step 1	Transmission link capacity updates	APS --> Mead (150 MW new) COB --> West Main (from 206 to 222 MW in average)	(1,692,504)
Step 2	Varible O & M Cost in Dispatching Tier prices		1,796,024
Step 3	a. new QF contract	New QFs: Sage Solar I, II, III	1,022,157
	b. Contract Delay Rate (CDR)	CDR for QFs coming online after 2018	(290,039)
Step 4	2017 Flexble Reserve Study in 2017 IRP		(3,223,732)
Step 5	Wind Capacity Factor Methodology Change		4,644,500
Step 6	DA/RT (starting EIM)	DART historicial period based on the months joining EIM	(2,245,827)
Step 7	Coal Plant Economic Cycling		(740,681)
Step 8	Thermal Attributes updates	**Minimum Operationa Level Change:** Hunter 1: 121.9MW (was 112.5MW) Hunter 2 :78.4MW (was 72.4MW) Huntington 1 :100MW (was 120MW) Huntington 2 :100MW (was 120MW) Naughton 1 :30MW (was 35MW) Wyodak :144MW (was 176MW) Current Creek :264MW (was 280MW) Lake Side 2 : 365MW (was 354MW)	(111,184)
Step 9	Pioneer Wind Shape		522,288
ORTAM19			$ 1,501,455,411

Docket No. UE 339
Exhibit PAC/109
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

March 1 Notice Letter and Supplement

March 2018

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2018

VIA ELECTRONIC MAIL

Attn: Parties to docket UE 323

RE: 2019 Transition Adjustment Mechanism – PacifiCorp's Notice of Methodology Changes

Under the Transition Adjustment Mechanism (TAM) Guidelines, PacifiCorp d/b/a Pacific Power provides this Notice of Methodology Changes for the 2019 TAM. This notice complies with an amendment to the TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-432. This amendment provides that "[t]he Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the GRID[1] model or to the logic of the GRID model by March 1st of the year of a stand-alone TAM filing."[2] Under another amendment to the TAM Guidelines adopted in Order No. 13-474, the Commission removed the requirement for filing general rate cases concurrently with the TAM by March 1, allowing PacifiCorp to file a general rate case at any time during the year. Because PacifiCorp does not plan to file a general rate case by the April 1 filing date for the 2019 TAM, the company is treating the 2019 TAM as a stand-alone filing for purposes of the methodology change notice requirement.

Per Order No. 17-444 (2018 TAM Order), PacifiCorp has held a series of collaborative workshops with parties[3] to examine the possibility of transferring renewable energy certificates (RECs) to an electric service supplier (ESS) for direct access customers, coal contracting procedures, the economic dispatch of coal resources, and GRID model validation. PacifiCorp also convened separate workshops, as ordered by the Commission, to discuss the company's approach to developing its long-term fuel strategy for the Jim Bridger plant.

PacifiCorp provides notice of the following planned changes to the 2019 TAM:

- PacifiCorp will transfer RECs to the ESS of a direct access customer.
- The regulating reserve requirements will be updated to be consistent with the flexible reserve study in 2017 integrated resource plan.
- Certain coal plants will be allowed to cycle for economics during the spring season.
- Variable operations and maintenance costs will be included in the dispatch price of thermal resources.
- The capacity factor used for company-owned wind will be based on the historical average capacity factor.

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[1] Generation and Regulation Initiative Decision Tools model.

[2] *In the Matter of PacifiCorp d/b/a Pacific Power 2010 Transition Adjustment Mechanism*, Docket UE-207, Order No. 09-432, Appendix A at 4-5 (Oct. 30, 2009).

[3] Parties participating in the workshops include Commission Staff, Citizens' Utility Board of Oregon, Industrial Customers of Northwest Utilities, Calpine Energy Solutions LLC, and Sierra Club.

PacifiCorp will include an exhibit to testimony in the direct filing identifying all changes based on discussions with the parties as outlined above.

Please direct any questions regarding this notice to me at 503-813-6583.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

cc: UE 323 Service List

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 27, 2018

VIA ELECTRONIC MAIL

Attn: Parties to docket UE 323

RE: 2019 Transition Adjustment Mechanism–PacifiCorp's Notice of Methodology Changes–Supplement

On March 1, 2018, PacifiCorp d/b/a Pacific Power provided its notice of methodology changes for the 2019 Transition Adjustment Mechanism (TAM) in accordance with the TAM Guidelines. In preparing the 2019 TAM, the company has identified two adjustments that were inadvertently not included in the March 1, 2018 letter. PacifiCorp notes that the changes identified below are not substantial changes to the logical constructs, methodologies or calculations, but rather minor adjustments. However, in the interest of transparency, PacifiCorp is providing notice of the following adjustments:

- Energy Imbalance Market (EIM) benefits will be forecasted using a linear trend based on actual monthly EIM benefits beginning with December 2015.
- The hourly shape of new wind power purchase agreements, including qualifying facilities (QF), will be based on proxy wind resource(s). This change impacts one wind QF in the 2019 TAM, Pioneer Wind.

As previously mentioned, PacifiCorp will include an exhibit to testimony in the direct filing identifying all changes. We expect to file the 2019 TAM on March 30, 2018.

Please direct any questions regarding this notice to me at 503-813-6583.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

cc: UE 323 Service List

Docket No. UE 339
Exhibit PAC/110
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Time Series of Fixed Generation Costs

March 2018

PacifiCorp Fixed Generation Revenue Requirement (Oregon Allocated)

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2006-2015 CAGR	2007-2016 CAGR
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948		
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739		
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756		
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569		
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851		
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785		
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414		
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138		
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898		
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)		
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)		
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097	**7.98%**	**3.82%**
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821	**-0.06%**	**-0.62%**
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**	**8.04%**	**4.46%**
Removal of New Generation Resources													
Gross Plant in Service	(49,761,699)	(176,569,028)	(369,536,740)	(559,776,877)	(655,685,369)	(691,632,310)	(679,220,340)	(660,057,047)	(749,958,320)	(839,283,616)	(867,921,408)		
Accumulated Depreciation	1,705,852	7,651,256	20,686,507	40,038,375	61,385,629	86,513,258	109,156,546	129,609,237	155,074,563	183,020,814	216,695,793		
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Total Rate Base Reduction	(48,055,847)	(168,917,772)	(348,850,233)	(519,738,503)	(594,299,740)	(605,119,052)	(570,063,794)	(530,447,810)	(594,883,757)	(656,262,802)	(651,225,615)		
Return On Rate Base	(4,280,568)	(13,785,379)	(28,166,907)	(42,769,281)	(49,511,111)	(48,609,213)	(43,986,122)	(40,669,513)	(45,104,432)	(49,420,494)	(49,264,453)		
Operating & Maintenance Expense													
Depreciation Expense	(1,705,852)	(5,995,311)	(12,827,327)	(19,865,909)	(23,216,345)	(24,649,243)	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)		
Amortization Expense													
Taxes Other Than Income													
Federal Income Taxes	(1,152,461)	(3,711,448)	(7,583,398)	(11,514,807)	(13,329,915)	(13,087,096)	(11,842,418)	(10,949,484)	(12,143,501)	(13,305,518)	(13,263,506)		
State Income Taxes	(156,600)	(504,324)	(1,030,458)	(1,564,671)	(1,811,314)	(1,778,319)	(1,609,188)	(1,487,853)	(1,650,100)	(1,807,999)	(1,802,290)		
Deferred Income Taxes													
Misc Revenue & Expenses													
Revenue Credits													
Revenue Requirement ($)	(7,295,480)	(23,996,463)	(49,608,090)	(75,714,668)	(87,868,684)	(88,123,871)	(81,645,062)	(76,630,981)	(82,748,888)	(91,093,242)	(91,795,493)		
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821		
Revenue Requirement ($/MWh)	(0.49)	(1.54)	(3.23)	(5.15)	(6.03)	(6.12)	(5.62)	(5.26)	(5.61)	(6.20)	(6.24)	2006-2015	2007-2016
Revenue Requirement excl. New Generation Resources ($)	209,896,932	302,885,496	349,056,308	296,297,704	312,502,506	320,711,844	318,614,906	344,446,602	363,416,119	342,433,533	366,157,604	**5.59%**	**2.13%**
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821	**-0.06%**	**-0.62%**
Revenue Requirement excl. New Generation Resources ($/MWh)	**14.20**	**19.49**	**22.75**	**20.14**	**21.44**	**22.27**	**21.92**	**23.66**	**24.65**	**23.29**	**24.90**	**5.65%**	**2.76%**
Net to Gross Factor	1.611629519												

Docket No. UE 339
Exhibit PAC/111
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

List of Expected or Known Contract Updates

March 2018

List of Known Items Expected to be Updated During the 2019 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. Purchase expenses of PGE Cove based on PGE projection.
10. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

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

Wheeling Expenses and Transmission

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

Other

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

Coal Expense Update Items

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

PacifiCorp
Coal and Transportation Contracts
Potential Updates in Reply Filing

		Captive		Fixed Price Coal Contracts		Variable Price Coal Contracts		Transportation Contracts	
Plant	Supplier/Mine	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company/Bridger	√	n/a						
	Lighthouse Resources/Black Butte			√	√				
	Union Pacific Railroad							√	√
Cholla	Peabody/El Segundo					√	√		
	BNSF Railway							√	√
Colstrip	Westmoreland/Rosebud					√	√	√	√
Craig	Trapper Mining Inc/Trapper	√	n/a						
Hayden	Peabody/Twentymile			√	n/a				
	Union Pacific Railroad							√	√
Hunter	Bowie/Sufco, Dugout, Skyline			√	√				
Huntington	Bowie/Sufco, Dugout, Skyline			√	√				
	Rhino Energy/Castle Valley			√	√				
	Utah Trucking							√	√
D Johnston	Unidentified PRB					√	√		
	Peabody/N. Antelope Rochelle			n/a	n/a				
	Western Fuels/Dry Fork					n/a	√		
	BNSF Railway							√	√
Naughton	Westmoreland/Kemmerer					√	√		
Wyodak	Black Hills/Wyodak					√	√		

Note - The table lists the coal and transportation contracts that may be affected by changes in volumes or pricing due to changes in forward price curves, market indices and inflation rates

Docket No. UE 339
Exhibit PAC/112
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Backcast Net Power Costs Study for 2016

March 2018

PacifiCorp

BackCast NPC 2016

Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
						$							
Special Sales For Resale													
Long Term Firm Sales													
1 Black Hills s27013/s28160	12,563,485	957,311	955,107	941,596	940,677	1,015,150	991,673	1,134,689	1,236,510	1,161,869	1,089,986	978,783	1,160,134
2 BPA Wind s42818	3,203,785	332,007	405,770	291,848	207,556	494,256	118,594	173,184	115,038	177,159	287,316	256,500	344,556
3 Hurricane Sale s393046	15,990	1,235	1,235	1,235	1,170	1,300	1,365	1,495	1,495	1,365	1,430	1,300	1,365
4 LADWP (IPP Layoff)	3,318,535	2,310,335	574,056	434,144	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	70,603	4,043	3,405	3,845	3,051	5,466	7,427	9,999	10,208	7,811	5,691	3,527	6,130
NVE s811499	-	-	-	-	-	-	-	-	-	-	-	-	-
Pacific Gas & Electric s524491	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO s100035	-	-	-	-	-	-	-	-	-	-	-	-	-
Salt River Project s322940	-	-	-	-	-	-	-	-	-	-	-	-	-
SCE s513948	-	-	-	-	-	-	-	-	-	-	-	-	-
SDG&E s513949	-	-	-	-	-	-	-	-	-	-	-	-	-
Shell Sale 2013-2014	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD s24296	-	-	-	-	-	-	-	-	-	-	-	-	-
5 UMPA II s45631	8,731,659	472,103	413,650	418,521	419,896	422,091	932,984	1,780,719	1,400,832	793,036	593,573	490,680	593,573
Total Long Term Firm Sales	27,904,057	4,077,034	2,353,224	2,091,188	1,572,351	1,938,264	2,052,042	3,100,086	2,764,084	2,141,240	1,977,996	1,730,790	2,105,758
Short Term Firm Sales													
COB	7,525,350	1,017,420	957,780	1,024,860	146,300	165,550	146,300	1,320,500	1,426,140	1,320,500	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	862,400	280,000	280,000	302,400	-	-	-	-	-	-	-	-	-
Mid Columbia	864,200	378,400	320,050	165,750	-	-	-	-	-	-	-	-	-
Mona	1,002,100	737,100	265,000	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	36,882,350	8,734,200	6,432,390	6,881,460	1,556,420	-	-	-	-	-	4,482,540	4,312,800	4,482,540
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	47,136,400	11,147,120	8,255,220	8,374,470	1,702,720	165,550	146,300	1,320,500	1,426,140	1,320,500	4,482,540	4,312,800	4,482,540
System Balancing Sales													
COB	19,194,246	2,215,028	738,745	397,370	882,082	1,130,271	1,520,833	2,363,104	1,917,866	2,694,186	1,763,756	1,555,380	2,015,627
Four Corners	59,781,769	4,385,486	3,573,011	3,871,346	5,790,897	3,443,728	3,355,963	5,193,561	6,128,515	6,608,747	5,680,671	5,317,957	6,431,891
Mead	25,050,725	2,393,141	1,988,714	1,153,018	1,282,308	1,216,753	1,191,553	2,528,401	2,677,377	3,056,151	2,460,568	2,142,493	2,960,252
Mid Columbia	29,917,909	5,233,860	3,164,486	2,022,866	720,047	669,316	591,467	1,577,686	2,468,691	4,208,962	4,842,758	2,105,768	2,312,003
Mona	16,400,545	762,696	433,240	788,314	561,378	1,191,671	1,074,479	1,095,789	1,699,053	2,921,969	1,476,644	2,104,260	2,291,052
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	48,869,529	850,888	1,378,156	822,540	3,392,958	5,011,708	5,282,885	7,845,104	6,294,143	5,935,102	3,765,435	3,344,564	4,946,048
EIM Exports	6,670,204	422,214	413,845	521,101	540,696	627,656	730,390	625,738	657,584	449,512	546,581	477,119	657,768
Trapped Energy	462,042	2,208	2,395	6,121	-	-	370,312	25,484	-	-	35,125	6,970	13,427
DA-RT Balancing	46,571,784	2,702,542	1,982,328	1,600,801	2,175,726	3,430,869	5,295,738	7,147,307	6,944,413	4,267,801	3,033,297	2,657,806	5,333,155
Total System Balancing Sales	252,918,754	18,968,061	13,674,919	11,183,477	15,346,092	16,721,971	19,413,620	28,402,172	28,787,641	30,142,429	23,604,834	19,712,316	26,961,222
Total Special Sales For Resale	327,959,211	34,192,214	24,283,363	21,649,135	18,621,163	18,825,785	21,611,962	32,822,758	32,977,864	33,604,169	30,065,370	25,755,906	33,549,520

PacifiCorp

BackCast NPC 2016

Net Power Cost Analysis

Purchased Power & Net Interchange

	12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
	Long Term Firm Purchases													
6	APS Supplemental p27875	717,362	8,787	-	73,961	27,599	21,456	16,529	21,662	59,693	97,032	132,701	101,985	155,960
	Blanding Purchase p379174	-	-	-	-	-	-	-	-	-	-	-	-	-
	BPA Reserve Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
	Combine Hills Wind p160595	5,539,691	347,483	484,546	589,657	472,656	505,664	449,304	437,633	368,136	405,360	462,668	508,454	508,129
7	Deseret Purchase p194277	27,099,336	2,329,856	1,985,340	2,221,939	2,268,101	1,758,375	2,310,845	2,342,716	2,537,938	2,288,949	2,242,382	2,279,978	2,532,918
8	Douglas PUD Settlement p38185	2,144,642	15,052	105,119	260,115	298,607	341,480	255,100	173,619	124,558	86,670	199,834	219,650	64,838
9	Eagle Mountain - UAMPS/UMPA	2,627,238	170,786	148,314	249,367	133,805	237,601	267,371	294,460	257,580	244,525	207,677	172,411	243,341
10	Gemstate p99489	1,182,925	106,300	102,900	105,100	102,900	102,900	102,900	102,900	115,500	102,900	137,228	137,228	(35,831)
	Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
	Grant County 10 aMW p66274	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Hermiston Purchase p99563	33,576,091	6,462,280	5,933,329	5,704,877	4,950,105	5,092,684	5,432,816	-	-	-	-	-	-
12	Hurricane Purchase p393045	126,653	14,859	14,450	10,706	8,658	7,313	6,669	11,934	14,625	12,870	8,600	7,137	8,834
13	IPP Purchase	3,318,535	2,310,335	574,056	434,144	-	-	-	-	-	-	-	-	-
	Kennecott Generation Incentive	-	-	-	-	-	-	-	-	-	-	-	-	-
	LADWP p491303-4	-	-	-	-	-	-	-	-	-	-	-	-	-
	MagCorp p229846	-	-	-	-	-	-	-	-	-	-	-	-	-
	MagCorp Reserves p510378	6,877,150	561,400	553,380	581,450	593,480	573,430	561,400	569,420	573,430	581,450	589,470	581,450	557,390
	Nucor p346856	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
	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
14	PGE Cove p83984	134,406	11,000	16,000	16,000	16,000	16,000	16,000	(36,594)	16,000	16,000	16,000	16,000	16,000
	Rock River Wind p100371	5,172,608	634,125	565,523	497,722	405,963	310,106	212,514	297,587	205,140	333,928	541,180	457,835	710,986
15	Small Purchases east	41,271	3,389	4,921	3,862	3,323	3,076	3,130	3,297	3,513	3,113	3,074	3,066	3,507
	Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
	Three Buttes Wind p460457	21,298,088	2,675,222	2,596,379	2,241,147	1,429,677	1,249,664	1,065,519	1,059,063	1,164,863	1,455,837	2,050,300	1,851,034	2,459,384
	Top of the World Wind p522807	42,969,257	4,690,983	5,216,331	4,495,225	2,918,842	2,723,261	2,051,174	2,200,106	2,502,764	3,154,359	4,201,074	4,004,474	4,810,665
16	Tri-State Purchase p27057	8,994,013	728,818	699,849	740,463	723,868	716,920	764,705	775,176	777,111	789,359	772,447	760,834	744,461
	West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wolverine Creek Wind p244520	10,244,095	778,571	934,499	1,023,699	834,235	720,278	748,977	801,862	596,207	717,238	1,133,836	847,851	1,106,843
	Long Term Firm Purchases Total	199,193,159	24,110,062	22,195,751	21,510,248	17,448,633	16,641,023	16,525,769	11,315,657	11,577,874	12,550,409	14,959,287	14,210,203	16,148,242
	Seasonal Purchased Power													
	Constellation 2013-2016	4,306,036	-	-	-	-	-	-	1,472,850	1,513,603	1,319,584	-	-	-
	Seasonal Purchased Power Total	4,306,036	-	-	-	-	-	-	1,472,850	1,513,603	1,319,584	-	-	-

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Net Power Cost Analysis

	12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
	Qualifying Facilities													
17	QF California	7,979,979	711,058	1,002,185	1,111,824	1,070,400	704,258	370,728	285,159	389,632	341,270	416,241	772,108	805,115
18	QF Idaho	8,078,869	531,403	536,765	634,565	608,474	889,054	888,288	755,225	653,064	580,500	666,250	712,857	622,424
19	QF Oregon	24,455,986	1,957,523	2,060,644	2,761,300	2,656,145	2,260,025	1,958,793	1,856,798	1,832,038	1,696,489	1,789,262	1,732,083	1,894,888
20	QF Utah	7,275,178	492,656	571,860	630,872	618,564	677,014	680,889	628,603	601,554	659,334	618,572	559,171	536,088
21	QF Washington	301,945	6,521	6,083	5,350	19,719	50,440	58,518	60,636	57,230	31,859	5,589	-	-
22	QF Wyoming	281,635	35,211	36,768	35,137	24,539	18,766	12,660	24,356	19,455	15,638	20,675	17,697	20,732
23	Biomass One QF	14,257,282	1,344,832	1,361,635	1,396,119	1,373,827	865,864	854,754	875,125	1,387,865	1,474,954	1,388,906	1,410,194	523,207
	Black Cap II Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Butter Creek Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Champlin Blue Mtn Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Chevron Wind p499335 QF	774,591	53,081	77,734	87,211	41,919	38,703	31,263	54,828	55,775	63,102	80,045	58,234	132,697
	Chopin Wind QF	333,613	-	-	-	-	-	-	-	-	-	8,311	157,777	167,524
	Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
24	DCFP p316701 QF	100,096	438	3,911	5,050	6,683	6,754	12,693	11,634	6,001	15,815	14,804	8,324	7,990
	Co-Gen II p349170 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Enterprise Solar I QF	4,497,225	-	-	-	-	97,161	571,285	937,233	704,237	511,500	408,448	718,695	548,665
26	Escalante Solar I QF	2,961,710	-	-	-	-	-	-	500,576	610,726	486,377	379,989	591,532	392,511
27	Escalante Solar II QF	3,195,581	-	-	-	-	-	-	761,538	663,180	482,781	363,187	553,812	371,083
28	Escalante Solar III QF	3,187,028	-	-	-	-	-	-	860,370	650,635	473,647	375,752	497,532	329,092
29	Evergreen BioPower p351030 QF	3,460,539	193,070	170,894	229,915	313,067	315,201	350,202	365,011	384,905	345,514	287,479	257,406	247,877
30	ExxonMobil p255042 QF	11,023	-	-	-	-	-	-	11,023	-	-	-	-	-
	Five Pine Wind QF	6,014,463	499,376	679,260	689,897	597,182	390,253	480,816	674,351	419,768	-	-	559,722	1,023,839
	Foote Creek III Wind QF	1,691,040	184,346	247,901	220,196	106,580	83,687	55,595	119,921	81,246	98,084	169,276	129,805	194,403
31	Granite Mountain East Solar QF	2,344,172	-	-	-	-	-	-	-	424,537	253,654	642,410	598,886	424,685
32	Granite Mountain West Solar QF	1,095,004	-	-	-	-	-	-	-	93,902	153,080	174,856	385,985	287,182
33	Iron Springs Solar QF	4,775,689	-	-	-	-	-	566,989	637,508	713,203	1,009,815	769,582	625,471	453,120
	Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Latigo Wind Park QF	6,719,696	124,186	312,167	611,150	621,056	517,787	623,677	562,074	544,442	721,093	588,972	841,322	651,770
	Long Ridge Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Mariah Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Mountain Wind 1 p367721 QF	8,554,871	607,320	1,364,828	834,060	533,995	472,883	387,165	800,161	457,730	652,004	655,689	518,140	1,270,896
	Mountain Wind 2 p398449 QF	13,810,177	1,557,056	1,946,200	1,292,427	791,302	671,061	695,566	1,421,300	816,512	1,042,453	1,010,201	730,122	1,835,978
	North Point Wind QF	13,301,755	1,056,849	1,385,395	1,623,859	1,338,485	867,193	1,072,914	1,620,426	1,017,455	-	-	1,289,189	2,029,990
	OM Power I Geothermal QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Oregon Wind Farm QF	11,190,364	546,005	821,602	1,134,346	1,127,698	1,272,240	1,043,417	1,137,555	970,743	1,013,396	841,765	493,946	787,653
	Orem Family Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Pavant II Solar QF	176,112	-	-	-	-	-	-	-	-	-	5,141	91,217	79,754
35	Pioneer Wind Park I QF	2,949,562	-	-	-	-	-	-	-	-	26	543,251	1,235,804	1,170,482
	Power County North Wind QF p5756	4,543,222	317,810	401,411	459,991	344,884	237,078	261,217	399,547	348,606	342,787	466,350	362,275	601,265
	Power County South Wind QF p575(	3,877,578	230,629	380,150	412,237	306,744	203,859	215,693	299,801	284,899	274,101	436,246	306,711	526,506
36	Roseburg Dillard QF	705,545	48,294	44,104	47,936	77,063	79,287	37,033	78,249	64,422	36,447	78,490	64,238	49,983
	SF Phosphates	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sigurd Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
	Spanish Fork Wind 2 p311681 QF	2,663,411	249,778	160,479	164,025	147,309	153,920	207,937	272,688	310,257	218,148	228,033	276,288	274,549
37	Sunnyside p83997/p59965 QF	27,501,790	2,552,886	2,438,780	2,491,671	859,282	2,277,211	2,523,557	2,515,938	2,566,875	2,199,745	2,314,325	2,475,419	2,286,100
	Tata Chemicals QF	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Tesoro QF	476,569	43,633	36,068	56,242	42,363	84,240	11,226	8,349	13,448	30,737	49,078	45,221	55,963
	Threemile Canyon Wind QF p50013(	1,548,067	64,094	92,767	147,808	179,036	201,238	179,355	163,705	119,511	120,146	88,844	93,048	98,514
39	Three Peaks Solar QF	235,041	-	-	-	-	-	-	-	-	-	-	-	235,041
	US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Utah Pavant Solar QF	3,707,324	135,636	193,680	244,549	299,777	375,843	440,743	553,526	456,838	394,174	272,513	227,187	112,858
41	Utah Red Hills Solar QF	5,007,102	187,256	241,930	263,645	303,128	381,882	686,107	943,477	698,903	496,669	386,909	209,861	207,334
	Qualifying Facilities Total	204,040,830	13,730,947	16,575,197	17,591,385	14,409,221	14,192,902	15,279,078	20,196,693	18,419,593	16,235,340	16,545,438	19,607,279	21,257,756
	Mid-Columbia Contracts													
		-												
		-												
		-												
	Mid-Columbia Contracts Total	4,236,278	365,001	365,001	365,001	185,339	365,001	365,001	365,001	365,001	373,984	373,984	373,984	373,984
	Total Long Term Firm Purchases	411,776,303	38,206,010	39,135,949	39,466,634	32,043,194	31,198,926	32,169,848	33,350,201	31,876,070	30,479,316	31,878,709	34,191,465	37,779,982

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Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647	-	-	-	-	-	-	-	-	-	-	-	-	-
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	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
Mid Columbia	46,434,030	6,899,100	6,891,210	7,338,720	1,326,440	124,700	110,200	3,324,000	3,589,920	3,324,000	4,559,470	4,386,800	4,559,470
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	47,222,510	7,155,100	7,147,210	7,615,200	1,326,440	124,700	110,200	3,324,000	3,589,920	3,324,000	4,559,470	4,386,800	4,559,470
System Balancing Purchases													
COB	11,637,320	340,782	515,335	877,970	1,178,722	1,128,736	1,112,655	1,670,876	1,807,835	595,075	363,973	441,146	1,604,215
Four Corners	10,406,947	957,881	381,232	715,696	140,098	714,823	2,082,617	1,719,286	1,605,495	360,795	730,436	303,649	694,940
Mead	212,166	29,988	15,314	64,426	11,257	12,271	30,991	13,274	13,617	2,472	3,063	4,254	11,239
Mid Columbia	40,552,358	605,606	856,286	343,635	2,619,157	4,618,677	9,269,306	8,560,258	5,444,091	1,217,259	998,714	3,035,811	2,983,560
Mona	9,459,837	644,413	894,950	953,643	1,139,349	1,152,071	1,289,757	997,437	786,244	290,169	322,944	293,485	695,374
NOB	4,278,392	9,604	-	-	19,914	162,983	789,917	735,946	1,263,279	326,186	4,693	-	965,871
Palo Verde	4,033,099	1,458,569	588,875	1,029,337	2,039	-	-	-	-	-	247,224	329,937	377,119
EIM Imports	(1,246,205)	(119,318)	(119,318)	(119,318)	(119,318)	(119,318)	(72,915)	(72,915)	(72,915)	(72,915)	(119,318)	(119,318)	(119,318)
Emergency Purchases	106,932	3,193	3	847	21,747	5,185	14,336	-	-	13,371	48,249	-	-
DA-RT Balancing	97,539,158	5,706,318	5,569,064	5,394,364	7,101,772	8,952,508	11,010,720	12,520,021	11,553,919	7,845,382	6,255,846	6,480,009	9,149,236
Total System Balancing Purchases	176,980,004	9,637,036	8,701,739	9,260,600	12,114,736	16,627,935	25,527,384	26,144,183	22,401,565	10,577,793	8,855,824	10,768,974	16,362,234
Total Purchased Power & Net Inte	641,378,817	55,448,146	55,434,899	56,792,434	45,934,370	48,401,560	58,257,431	63,268,384	58,317,555	44,831,109	45,744,003	49,797,239	59,151,687

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2016	01/16-12/16	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Wheeling & U. of F. Expense													
Firm Wheeling	148,076,415	12,681,970	13,155,489	13,551,947	12,743,042	11,820,862	11,979,724	12,051,073	11,468,983	11,895,301	12,086,927	11,984,247	12,656,851
C&T EIM Admin fee	451,314	42,418	34,574	33,056	30,983	33,644	39,312	43,406	44,083	39,758	36,333	33,119	40,630
ST Firm & Non-Firm	12,558	405	69	7	-	3,248	1,052	1,343	2,964	45	-	1,865	1,562
Total Wheeling & U. of F. Expense	148,540,287	12,724,793	13,190,132	13,585,009	12,774,024	11,857,754	12,020,087	12,095,821	11,516,030	11,935,104	12,123,260	12,019,231	12,699,042
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	36,391,712	2,391,989	2,085,131	2,144,871	2,648,693	2,752,282	3,374,867	4,046,918	3,938,018	3,989,505	3,322,462	2,224,233	3,472,742
Colstrip	16,109,393	1,571,295	1,339,089	1,233,390	1,182,257	909,489	795,356	1,584,094	1,609,357	1,531,367	1,360,341	1,463,052	1,530,306
Craig	21,408,258	1,895,075	1,563,448	1,619,292	1,913,610	1,832,715	1,890,814	2,217,875	2,245,192	1,340,636	1,130,162	1,689,337	2,070,101
Dave Johnston	59,686,562	4,642,170	4,147,552	4,472,782	4,424,998	5,053,346	5,562,994	5,613,292	5,729,104	5,494,136	4,831,676	4,886,817	4,827,694
Hayden	10,009,043	815,781	751,202	680,324	490,185	631,370	920,003	990,474	1,077,550	1,043,302	953,079	765,968	889,806
Hunter	134,378,520	10,927,003	9,058,014	7,880,401	9,244,940	10,161,394	11,072,752	13,723,645	13,290,065	13,679,510	12,586,155	9,432,627	13,322,012
Huntington	96,807,003	9,144,352	5,533,836	5,723,007	6,034,487	6,096,100	9,145,427	9,720,773	10,937,538	9,726,895	7,473,644	6,149,799	11,121,144
Jim Bridger	140,714,988	12,073,242	7,107,650	7,012,396	6,826,515	8,830,581	13,035,003	17,250,809	18,941,676	13,085,732	9,274,956	8,531,484	18,744,942
Naughton	110,677,628	9,941,500	8,711,348	8,926,484	7,490,709	8,275,557	9,749,688	9,314,166	9,969,540	9,548,343	10,055,651	8,785,551	9,909,092
Wyodak	25,883,854	2,608,019	2,441,007	2,437,989	1,252,863	1,524,123	-	2,589,846	2,761,126	2,651,496	2,649,564	2,324,684	2,643,137
Total Coal Fuel Burn Expense	652,066,961	56,010,427	42,738,278	42,130,936	41,509,258	46,066,958	55,546,904	67,051,891	70,499,167	62,090,923	53,637,691	46,253,552	68,530,976
Gas Fuel Burn Expense													
Chehalis	46,740,114	5,330,296	2,709,009	3,271,379	2,515,278	3,058,292	3,631,389	5,900,832	5,050,564	5,926,885	5,870,636	1,782,692	1,692,862
Currant Creek	51,031,364	5,419,921	3,715,299	3,448,174	2,638,586	1,715,676	4,838,492	5,558,411	5,507,550	5,037,059	3,723,881	4,708,701	4,719,614
Gadsby	2,658,783	-	-	-	-	-	41,852	1,195,874	1,174,239	246,817	-	-	-
Gadsby CT	2,030,682	111,329	-	40,053	44,946	46,456	208,665	535,124	393,872	307,730	175,510	98,624	68,375
Hermiston	29,243,755	2,719,298	2,237,843	2,006,120	1,289,760	1,417,158	1,747,689	2,936,198	3,146,842	3,156,448	2,623,118	2,332,999	3,630,284
Lake Side 1	64,649,060	6,337,636	4,032,606	2,687,447	4,191,858	4,761,119	6,063,126	6,866,080	7,212,068	5,169,574	4,543,011	5,732,364	7,052,170
Lake Side 2	58,555,275	5,532,346	4,382,188	2,086,952	3,337,655	4,245,397	5,218,563	5,658,451	5,612,931	5,538,015	5,443,516	4,821,720	6,677,540
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	254,909,033	25,450,826	17,076,945	13,540,126	14,018,082	15,244,098	21,749,777	28,650,969	28,098,066	25,382,528	22,379,672	19,477,101	23,840,844
Gas Physical	(326,183)	(53,708)	(50,243)	(53,708)	(23,625)	(24,413)	(23,625)	(24,413)	(24,413)	(23,625)	(24,413)	-	-
Gas Swaps	48,295,887	5,195,138	6,491,963	7,345,213	5,658,438	5,736,469	3,750,563	2,834,069	2,574,119	1,996,088	2,317,719	3,579,100	817,013
Clay Basin Gas Storage	865,029	116,299	219,118	272,257	53,143	53,143	53,143	53,143	53,143	53,143	53,143	73,356	(188,003)
Pipeline Reservation Fees	37,756,716	3,167,471	3,071,244	3,167,471	3,119,357	3,167,471	3,119,357	3,183,782	3,183,782	3,136,808	3,183,782	3,104,608	3,151,583
Total Gas Fuel Burn Expense	341,500,483	33,876,026	26,809,027	24,271,359	22,825,395	24,176,768	28,649,215	34,697,551	33,884,697	30,544,941	27,909,904	26,234,165	27,621,437
Other Generation													
Blundell	4,531,067	452,194	379,347	449,447	77,956	303,423	394,235	389,209	405,130	385,733	422,759	436,708	434,927
Dunlap I Wind p524168	-												
Foote Creek I Wind	-												
Glenrock Wind p423461	-												
Glenrock III Wind p454125	-												
Goodnoe Wind p332427	-												
High Plains Wind p492251	-												
Leaning Juniper 1 p317714	-												
Marengo I Wind p332428	-												
Marengo II Wind p423463	-												
McFadden Ridge Wind p492250	-												
Rolling Hills Wind p423462	-												
Seven Mile Wind p454126	-												
Seven Mile II Wind p357819	-												
Integration Charge	6,266,778	486,244	545,588	519,647	406,986	398,182	426,913	551,912	515,935	548,687	609,373	580,062	677,249
Total Other Generation	10,797,845	938,438	924,935	969,094	484,942	701,605	821,147	941,120	921,066	934,421	1,032,132	1,016,770	1,112,176
Net Power Cost	**1,466,325,182**	124,805,615	114,813,907	116,099,696	104,906,825	112,378,860	133,682,823	145,232,009	142,160,650	116,732,328	110,381,619	109,565,051	135,565,798
Net Power Cost/Net System Load	**25.15**	**23.84**	**25.06**	**25.46**	**24.79**	**25.03**	**25.97**	**26.09**	**25.93**	**25.61**	**24.48**	**24.29**	**25.02**

REDACTED
Docket No. UE 339
Exhibit PAC/200
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Dana M. Ralston

March 2018

DIRECT TESTIMONY OF DANA M. RALSTON

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ATTACHED EXHIBITS

Exhibit PAC/201 – Long Term Coal Contract Presentation Provided at February 23, 2018 Workshop

Highly Confidential Exhibit PAC/202 – PacifiCorp Coal Inventory Policies and Procedures – Updated March 20, 2018

Highly Confidential Exhibit PAC/203 – Coal Inventory Study – Prepared by RPM Global – March 19, 2018

Highly Confidential Exhibit PAC/204 – PacifiCorp Long-Term Fuel Supply Plan for the Jim Bridger Plant – March 2018

QUALIFICATIONS

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

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

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I was previously the Vice President of Coal Generation and Mining from March 2015 to November 2017, and Vice President of Thermal Generation from January 2010 to March 2015. For 29 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's generation organization, including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operating and maintaining PacifiCorp's coal- and gas-fired generation fleet, coal fuel supply, and mining.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified on behalf of the company in proceedings before the Public Utility Commission of Oregon (Commission) and the public utility commissions in Utah, Washington, and Wyoming.

PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. I explain PacifiCorp's overall approach to providing the coal supply for its coal-fired generating plants, and I support the level of coal costs included in fuel expense in PacifiCorp's 2019 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony will:

- Explain PacifiCorp's process for developing the terms and conditions of long-term coal contracts, and its process for managing risk in long-term coal contracts;
- Explain the primary causes behind the changes to the total-company coal-fuel expense reflected in the 2019 TAM;
- Review the status of the Jim Bridger Long-Term Fuel Plan, and discuss the 2019 fuel supply costs for the Jim Bridger plant; and
- Provide coal pricing and background on third-party coal contracts and at affiliate-owned mines.

COMPLIANCE WITH 2018 TAM ORDER ISSUES

Q. Did PacifiCorp meet with Commission staff (Staff) and other parties to conduct a coal issues workshop as directed by the Commission in the 2018 TAM?

A. Yes. PacifiCorp met with parties on February 23, 2018, as directed by Order No. 17-444, for a workshop to discuss coal issues. PacifiCorp reported on the results of the workshop during the Commission's March 13, 2018 public meeting. PacifiCorp's presentation from the February 23, 2018 workshop is attached as Exhibit PAC/201. The following items were discussed during the workshop:

1) PacifiCorp's process by which the terms and conditions of long-term coal contracts are developed, negotiated and approved, and how the company accounts for plant fuel requirements when negotiating long-term contracts or coal mine investment decisions;

2) PacifiCorp's process for managing risk in long-term coal contracts related to: (a) price; (b) contract length; (c) minimum take provisions; (d) liquidated damages; and (e) changing electricity market conditions;

3) How long-term coal contract provisions impact dispatch decisions in the Generation and Regulation Initiative Decision Tools model (GRID), commitment decisions, and long-term system modeling decisions;

4) How (a) long-term coal contracts, (b) fuel transportation contracts, and (c) spot market coal fuel purchases are each reviewed before the Commission;

5) The potential development of a method to reflect variable operations and maintenance (O&M) costs in net power costs, including classification of which O&M costs should be treated as variable and the treatment of variable O&M in rates; and

6) Coal plant economic cycling modeling.

My testimony addresses three of the six items: the company's process for developing the terms and conditions of long-term coal contracts, the process for managing risk in long-term coal contracts, and how coal and transportation contracts are reviewed before the Commission. Mr. Michael G. Wilding's testimony addresses the other Commission directives.

Q. What is PacifiCorp's process by which the terms and conditions of long-term coal contracts are developed?

A. The company's business plan is used to determine long-term fuel requirements for the coal plants. Once the requirements are determined, the Fuels department uses that information to develop coal portfolios that minimize costs, taking into account the plant's stockpile inventory but still allowing some degree of upward or downward flexibility for changing market conditions.

Q. How does the company account for plant fuel requirements when negotiating long-term contracts or coal mine investment decisions?

A. PacifiCorp uses the GRID model to determine generation levels for the company's power system.[1] PacifiCorp's process in developing and negotiating long-term contracts evaluates the following factors: plant location/coal region, coal supply options, coal transportation options, coal quality constraints, and other market alternatives. Proposals are evaluated on a least-cost, least-risk basis considering the variables of term length, volume, and price. PacifiCorp may also solicit suppliers for coal through requests for proposals (RFP) where applicable. Each plant is located in a specific coal region or basin with unique opportunities and constraints. Each plant also has different transportation methods including rail, trucking, mine-mouth conveyor, or a combination of options. The coal plants were originally designed to consume coal from regional coal sources. Additional plant capital may be required in order to consume coal from different regions depending upon the coal quality available or delivery methods. Other factors impacting market alternatives include the number of coal suppliers available, liquid versus illiquid markets, and a coal supplier's operating history and financial strength.

Q. How does the company approve coal and transportation agreements?

A. PacifiCorp's internal legal and credit/risk departments review each contract before approval and execution. The approval authorization signature of each contract is in accordance with PacifiCorp's governance policies.

[1] The GRID model used for budget purposes is different than the GRID model used in the Oregon TAM. The budget GRID model is used to determine the net power cost budget, but is not subject to the same normalizing and regulatory modeling constraints as the GRID model used in the Oregon TAM.

Q. What is PacifiCorp's process for managing risk in long term coal contracts related to price, contract length, minimum take provisions, liquidated damages, and changing electricity market conditions?

A. PacifiCorp utilizes as short of a contract term as practical while seeking an outcome that balances risk associated with supply, contract term, volume, and price.

PacifiCorp manages pricing risk by using one or more of the following arrangements dependent upon location: fixed priced agreements, tiered pricing agreements, price reopener provisions, capped market price reopener pricing provisions, and indexed pricing agreements.

Contract length is managed by determining the proper length, which includes evaluating and managing pricing and supply risk, contract extension options, contract termination provisions, and incorporating options for future plant retirement dates.

Minimum take provisions are managed by using nomination provisions, minimum/maximum volume provisions, volume flexibility, percentage take flexibility, shortfall/pre-delivery provisions, and re-sell rights.

Liquidated damages provisions are used where possible to avoid full take-or-pay payments. Liquidated damages represent a small percentage payment of the total price. They also can be used to protect PacifiCorp customers with "environmental out"[2] provisions. Liquidated damages may also be used to control the plant's total inventory.

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[2] Environmental out contract provisions include the option to reduce minimum volume requirements in a coal or transportation agreement to comply with future unknown environmental regulations or laws.

PacifiCorp manages changing electric market conditions by employing the following points: length of contracts, specific contract structure such as tiered pricing provisions and minimum take requirements, and, to some degree, flexing plant stockpile inventory levels up or down.

Q. How are PacifiCorp's long term coal and transportation contracts reviewed before the Commission?

A. The Commission and Staff review PacifiCorp-provided fuel cost information through the annual TAM and Power Cost Adjustment Mechanism filings. New and updated contracts are reviewed on a regular basis. Review of these agreements are subject to the applicable confidentiality provisions.

Q. Did PacifiCorp prepare an updated coal inventory report as directed by the Commission in the 2018 TAM proceeding?

A. Yes. The PacifiCorp Coal Inventory Policies and Procedures was updated March 20, 2018. This document is included as Highly Confidential Exhibit PAC/202 and sets forth the current policies, procedures, and practices developed by PacifiCorp for the management of coal stockpiles by the company's fuels department. PacifiCorp retained the consulting firm of RPM Global (RPM) to update their prior inventory studies from 2009-2010 and 2015. The 2018 RPM coal inventory study is included as Highly Confidential Exhibit PAC/203 of my testimony.

OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supplies for its coal plants in 2019?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 83.7 percent of its 2019 coal requirements with third-party coal supplies and 16.3 percent with coal from its affiliate mines. More specifically: (1) 53.7 percent of the total coal requirement will be supplied under fixed-price contracts; (2) 28.3 percent will be supplied under contracts that escalate or de-escalate based on changes to producer and consumer price indices; and (3) 1.7 percent of the total coal requirement will be supplied from a contract for the Dave Johnston plant to be negotiated during 2018 or 2019.

Confidential Table 1: Coal Source Deliveries

	Plant	Price Reopener	New Contract	MMBtus (000's)	MMBtus (000's)	Percent
Affiliate Mines						
Bridger Coal/Bridger	Jim Bridger			[redacted]		
Trapper Mining/Trapper	Craig					
Subtotal Affiliate Mines					[redacted]	16.3%
Fixed Price Contracts						
Lighthouse Resources/Black Butte	Jim Bridger		√	[redacted]		
Rhino Energy/Castle Valley	Huntington					
Bowie/Sufco, Dugout, Skyline	Huntington					
Bowie/Sufco, Dugout, Skyline	Hunter					
Peabody/Twentymile	Hayden					
Peabody/North Antelope Rochelle	Dave Johnston		√			
Subtotal Fixed Price Contracts					[redacted]	53.7%
Variable Price Contracts						
Peabody/El Segundo	Cholla			[redacted]		
Westmoreland/Rosebud	Colstrip					
Western Fuels/Dry Fork	Dave Johnston					
Westmoreland/Kemmerer	Naughton	√				
Black Hills/Wyodak	Wyodak	√				
Subtotal Variable Price Contracts					[redacted]	28.3%
Other						
Unidentified PRB Mines	Dave Johnston			[redacted]		
Total Other					[redacted]	1.7%
Total Coal Supplies					[redacted]	100%

Note: Delivered MMBtus are calculated from consumption estimates provided by the generation requirements in GRID to accommodate targeted inventory stockpiles

Q. Has total coal-fuel expense in the 2019 TAM decreased from the level reflected in PacifiCorp's 2018 TAM?

A. Yes. As stated in the testimony of Mr. Wilding, total coal-fuel expense has decreased by $91.9 million—from $809.4 million in the 2018 TAM final update to $717.5 million in this initial filing in the 2019 TAM.[3] This decrease is a result of a $104.5 million volume reduction in coal-fired generation, partially offset by approximately $12.6 million in higher coal prices.

JIM BRIDGER FUEL SUPPLY

Long-Term Fuel Plan

Q. Has PacifiCorp completed a new long-term fuel plan for the Jim Bridger plant?

A. Yes. PacifiCorp evaluated several fueling options to determine the least-cost, least-risk strategy for fueling the Jim Bridger plant. These options included different Bridger Coal Company mine plans and third-party coal alternatives. The different options and combinations are discussed in the PacifiCorp Long-Term Fuel Supply Plan for the Jim Bridger Plant – March 2018 (2018 Fuel Plan) attached with my testimony as Highly Confidential Exhibit PAC/204. In the 2018 Fuel Plan, the company addresses how to best meet the plant's lower fuel requirements compared to the prior fuel plan. The reduced dispatch and shorter operating lives for Jim Bridger Units 1 and 2 are consistent with the preferred portfolio in PacifiCorp's 2017 Integrated Resource Plan, which was filed April 4, 2017.

The identified fueling options were evaluated using a present value revenue requirement analysis and a risk assessment. The options were then given a composite

[3] All references to costs and volumes in my testimony are on a total-company basis unless noted otherwise.

ranking and the company identified the least-cost, least-risk scenario. While the current analysis shows Option F is the least-cost, least-risk option, Option D will continue to be analyzed as it is the lowest cost option. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking into consideration the cost and risk of the options and will change the long-term fuel plan as necessary to provide the least-cost, least-risk long-term fuel supply for the plant. The company is using Option F for the 2019 TAM and other regulatory and planning purposes, while still acknowledging Option D remains a viable option.

Q. Does PacifiCorp's development of the new long-term fuel plan for the Jim Bridger plant comply with Order No. 16-482 in the 2017 TAM?

A. Yes. In Order No. 16-482, the Commission directed PacifiCorp to delay filing the new long-term fuel plan to allow the company to informally meet with Staff and other parties. The Commission ordered the parties to discuss information and analysis required to meaningfully evaluate the long-term fuel plan, which was accomplished through three workshops held throughout 2017 and 2018.

Jim Bridger Third-Party Coal Supply in 2019

Q. Did the Black Butte coal supply and rail agreements expire at the beginning of 2018?

A. Yes. The current Black Butte coal supply agreement initially was set to expire at the end of 2017 but was extended through the second quarter of 2018 in order to receive [redacted] tons of coal deferred from the 2015-2017 contract. The Union Pacific Railroad (UPRR) transportation agreement expired at the end of 2017.

Q. How did PacifiCorp respond to the expiration of these contracts?

A. Consistent with PacifiCorp's near-term fuel strategy outlined in the 2018 Fuel Plan, the company held negotiations with the Black Butte mine to procure coal for a term of three to four years. A contract with a 44-month term, beginning May 1, 2018 and ending December 31, 2021, was executed with the Black Butte mine in February 2018. PacifiCorp has the option under the contract to extend the term an additional four months, through April 30, 2022, with no change in volume or price. Concurrent negotiations were held with UPRR for the coal transportation and a new contract was executed in February 2018 for deliveries from 2018 to 2021.

Q. What is the expected decrease in third-party coal prices for the Jim Bridger plant in the 2019 TAM?

A. Delivered coal cost for the Black Butte contract decreased from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, or [redacted] overall. The cost decrease is due to purchasing an additional [redacted] tons of Black Butte coal at a lower price compared to the 2018 TAM. The price of Black Butte coal delivered to the Jim Bridger plant decreases [redacted] per ton, from a weighted cost of [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM. The overall price decrease is approximately [redacted], or [redacted]. The new UPRR rail agreement is forecast to result in a [redacted] increase in delivered costs.

Bridger Coal Company

Q. Please explain how Bridger Coal Company's production levels have changed in the 2019 TAM.

A. Bridger Coal Company's base mine production has decreased from [redacted] tons in the 2018 TAM to [redacted] tons in the 2019 TAM, a reduction of [redacted]. Additionally, Bridger Coal Company base deliveries have decreased from [redacted] tons in the 2018 TAM to [redacted] tons in the 2019 TAM, a reduction of [redacted]. These changes are shown in Confidential Table 2 below.

Confidential Table 2: Bridger Coal Production

	Deliveries to Bridger Plant			Mine Production		
	2019 TAM	2018 TAM	Variance	2019 TAM	2018 TAM	Variance
Bridger Coal	[redacted]					
Surface Mine						
Underground Mine						

Q. Please describe the change in Bridger Coal Company costs in the 2019 TAM.

A. Bridger Coal Company costs for the base mine plan deliveries of [redacted] tons increase by [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM. This is an increase of [redacted] (a [redacted] increase in delivered mine cost partially offset by a [redacted] reduction due to higher heat content). Bridger Coal Company's heat content in the 2019 TAM is [redacted] British Thermal Units (Btu) per pound compared to only [redacted] Btu per pound in the 2018 TAM. An additional [redacted] tons of supplemental or incremental coal are currently projected to be delivered above the base mine plan, consistent with the 2018 TAM. The supplemental tons result in an additional savings of [redacted] due to the improved year-on-year heat content.

Q. Please explain the reasons for the cost increase at Bridger Coal Company.

A. The cost increase is primarily driven by increased depreciation and reclamation contributions associated with the mine plan change from Option D to Option F as explained in the 2018 Fuel Plan. In the 2019 TAM, the surface mine is scheduled to close at the end of [redacted]. In Option D and previous mine plans the scheduled closure was [redacted]. Due to the change in life of the surface mine, the life of mine assets will be depreciated over fewer years. Depreciation and depletion costs increase by [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, an increase of [redacted]. Final reclamation contributions also increase by [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM. This [redacted] increase is a result of accelerated annual contributions to the Bridger reclamation trust to fund the final reclamation cost associated with reclaiming and restoring the mine property after closure of the surface mine.

Q. Please explain the cost decrease associated with changes in coal inventory between the 2019 TAM and the 2018 TAM.

Q. A decrease of approximately [redacted], or [redacted] per ton, can be attributed to changes in the value of Bridger Coal Company's coal inventory. The 2018 TAM reflected a decrease in underground inventory levels of 135,527 tons and a decrease in surface inventory levels of 26,799 tons. The decrease in inventory levels in the 2018 TAM results in a decrease or credit of [redacted] to coal inventory and an increase or debit to coal expense. The 2019 TAM reflects a decrease in underground inventory levels of 9,031 tons and a projected decrease in surface inventory levels of 13,259 tons. The decrease in inventory levels in the 2019 TAM resulted in only [redacted] being credited to coal inventory and debited to coal expense.

Q. In Order No. 13-387, the Commission ordered the company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate mines.[4] In this filing, does PacifiCorp adjust the price of coal from Bridger Coal Company consistent with Order No. 13-387?

A. Yes. In the 2019 TAM, the company reduces Bridger Coal Company costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

TRAPPER MINE

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

A. In 2019, the Craig plant will be supplied exclusively by the Trapper mine, which is an affiliate captive mine owned by some of the Craig plant owners. PacifiCorp's share of the mine is 21.4 percent. The pricing under the coal supply agreement is primarily based upon the annual mine cost associated with the Trapper mine.

Q. Have Trapper mine costs changed from the 2018 TAM?

A. Yes. Trapper mine costs have increased [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, a [redacted] overall price increase. This increase is primarily attributable to inflation. Deliveries from Trapper mine have increased [redacted] from [redacted] tons in the 2018 TAM to [redacted] tons in the 2019 TAM.

[4] *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).

THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in third-party coal-supply costs in the 2019 TAM.

A. PacifiCorp expects a net increase in third-party coal-supply costs of [redacted], as shown in Confidential Table 3 below:

Confidential Table 3: Third-Party Coal and Transportation Contract Price

Plant	Contract	Millions ($)
Naughton	Kemmerer Coal	[redacted]
Wyodak	Wyodak Coal	
Dave Johnston	Powder River Basin Coal	
Dave Johnston	BNSF Rail	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR Rail	
Hunter	Bowie Coal	
Huntington	Bowie and Castle Valley Coal	
Cholla	El Segundo Coal	
Cholla	BNSF Rail	
Colstrip	Rosebud Coal	
Hayden	Twentymile Coal and UPRR Rail	
Total Third-Party Contract Price Increase/(Decrease)		

Q. Do some third-party coal contracts include minimum-take requirements?

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

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Please describe the coal supply arrangement for the Naughton plant in 2019.

A. The Naughton plant is supplied by Westmoreland's adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The coal supply agreement calculates tier-1 and tier-2 volumes and pricing based on a July to June contract year. Because Naughton Unit 3 is projected to stop burning coal in January 2019 to comply with the Wyoming Regional Haze State Implementation Plan, the 2019 TAM includes only Units 1 and 2 at Naughton.

The coal supply agreement contains an environmental response provision to reduce the minimum annual volume quantity in the event of a reduction in coal-fired generation at the plant due to changes in environmental laws or rules. As a result of the projected cessation of Unit 3 as a coal-fired resource, PacifiCorp exercised this provision and the annual minimum take-or-pay quantity was reduced from [redacted] tons to [redacted] tons. In lieu of a full take-or-pay payment of approximately [redacted] for tons below [redacted], an environmental shortfall payment of only [redacted] or [redacted] will be owed in 2019 related to [redacted] shortfall tons on deliveries of [redacted] tons in the 2018-2019 contract year. The environmental shortfall payment is a direct result of the reduction in the coal purchases due to the cessation of Naughton 3 as a coal-fired unit.

The third amendment to the coal supply agreement signed in June 2017 further adjusted the maximum annual volumes and tier pricing levels over the next several years. A contract minimum of [redacted] tons and maximum of [redacted] tons is now in effect from July 1, 2018 through June 30, 2019. The first [redacted] tons delivered in the 2018-2019 contract year will be priced at a tier-1 price, and tons above that level will be at the lower tier-2 price. As a result of the third contract amendment, from July 1, 2019 to June 30, 2020, the contract minimum will be [redacted] tons and the maximum will be [redacted] tons with the first [redacted] tons priced at a tier-1 price, and tons above that at the tier-2 price. Previous to this third amendment, [redacted].

Q. Please describe the Naughton plant's coal cost change from the 2018 TAM.

A. Delivered coal cost at the Naughton plant increased [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM ([redacted] overall), as shown in Confidential Table 4.

The change in the amount of coal purchased under each price tier—namely less tier-2 coal, which is lower priced coal than tier-1 coal—is the driver of [redacted] of the increase. The forecasted tier-2 coal delivered in calendar year 2019 is [redacted] tons lower than 2018 because of the cessation of Naughton Unit 3 as a coal-fired generation resource.

Another major driver of the price increase is the January 1, 2019 price reopener. The new 2019 price is based upon the actual mining costs at the Kemmerer mine for calendar year 2018. As a result of the reopener, the January 2019 coal price before royalties and taxes is forecast to increase by approximately [redacted] per ton, which results in an increase of [redacted] after royalties, taxes, and contract index escalation in 2019. The environmental shortfall payment of [redacted] makes up the balance of the [redacted] increase.

Confidential Table 4: Naughton Contract Tonnage

	2019 TAM			2018 TAM		
Contract Tiers	Tons	Dollars	Price	Tons	Dollars	Price
Naughton Plant	[redacted]			[redacted]		
Tier 1						
Tier 2						
Subtotal						
Other Coal Costs						
Kemmerer Btu Adjustment		[redacted]			[redacted]	
Environmental Shortfall						
Iron & Calcium Premiums						
Subtotal						
Naughton Plant Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Btu/lb			[redacted]			[redacted]
$/MMBtu						

Wyodak

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

A. Delivered coal cost has decreased from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, or [redacted] overall. The cost decrease is primarily the result of the July 2019 price reopener, per the long-term coal supply agreement with Wyodak Resources Development Corporation, partially offset by escalation in diesel fuel and other contract indices.

Dave Johnston

Q. Please describe the Dave Johnston plant coal supply cost decrease.

A. Dave Johnston plant delivered coal cost has decreased by [redacted] compared to the 2018 TAM, or [redacted]. The decrease is due to a reduction in rail costs of [redacted], as described in further detail below, partially offset by a coal cost increase of approximately [redacted].

Q. Please explain the unidentified coal for the Dave Johnston plant included in Confidential Table 1.

A. The Dave Johnston plant is projected to consume approximately [redacted] tons in 2019; the Company currently has [redacted] tons of coal for the plant under contract resulting in an unidentified or open position of [redacted] tons. The company will solicit coal supplies from Powder River Basin (PRB) mines through an RFP during 2018 or 2019 to fill the open position.

Q. What are the coal supply arrangements for the Dave Johnston plant in the 2019 TAM?

A. Following the April 2016 RFP, the company executed a coal supply agreement with Western Fuel's Dry Fork mine through 2019. The Dry Fork mine will supply [redacted] tons in 2019 ([redacted] of the plant's requirements). After the April 2017 RFP for PRB coal supplies, the company executed a coal supply agreement to purchase coal from Peabody Energy's North Antelope Rochelle mine through 2020. That mine will supply [redacted] tons in 2019 ([redacted] of the plant's requirements). The coal price for the Dave Johnston plant's open position of approximately [redacted] tons in the 2019 TAM reflects the average 2019 forward price for PRB 8400 Btu coal of [redacted] per ton, as published in Coal Daily in February 2018. The 2019 price is [redacted] higher than the lowest 2018 PRB 8400 Btu adjusted price quote received in the April 2017 RFP of [redacted] per ton that was used for the open position in the 2018 TAM.

The rail cost decrease of [redacted] is primarily a result of the new BNSF Railway agreement that replaced the existing contract that expired in 2017. The new rail price assumption includes a [redacted] decrease compared to the 2018 TAM.

Coal Supply Agreements for the Utah Plants

Q. Please explain how the company's Utah plants are supplied with coal in the 2019 TAM.

A. The Utah plants are sourced collectively through a portfolio of coal sources under three different multi-year coal supply agreements. The primary coal supply for the Hunter plant is provided through a coal supply agreement with Bowie Coal Sales, LLC (Bowie). The Hunter agreement is a "delivered to plant" agreement through 2020, and Bowie is responsible for the transportation of the coal from the mine to the plant.

The primary coal supply to the Huntington plant is also provided under a contract with Bowie through 2029. Coal received under this agreement is designated for the Huntington plant. This is also a "delivered to the plant" agreement that requires Bowie to pay the transportation costs, however, PacifiCorp is responsible for limited trucking cost escalation. The Huntington plant also receives coal under a coal supply agreement with Rhino Energy, LLC's Castle Valley mine.

Q. Does the 2019 TAM reflect Energy West pension costs?

A. Yes. As authorized by Order No. 15-161 in docket UM 1712, the 2018 TAM includes [redacted] for contributions to the 1974 United Mine Workers Association pension plan.[5] Approximately [redacted] is included in Huntington plant costs in the 2019 TAM, consistent with the 2018 TAM. Approximately [redacted] of the [redacted] in pension costs is included in Hunter plant costs in the 2019 TAM, consistent with the 2018 TAM.

Hunter

Q. Please describe the change in coal cost at the Hunter plant in the 2019 TAM?

A. Coal prices have increased [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM ([redacted] overall). The increase is primarily due to the inflation-index escalation under the Bowie agreement ([redacted]) and reduced tier-2 coal delivered ([redacted]) due to approximately [redacted] lower generation volume at the Hunter plant.

Q. Please describe how the termination of Prep Plant coal transfers during 2018 affects coal deliveries at the Hunter plant.

A. PacifiCorp sold the Prep Plant to Bowie as part of the Deer Creek closure transaction. The last of the remaining PacifiCorp coal inventory at the Prep Plant will be delivered in 2018. This reduction of [redacted] tons in the 2019 TAM results in a cost decrease of approximately [redacted].

Huntington

Q. What coal supply costs for the Huntington plant are included in the 2019 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, an increase of [redacted] per ton or

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

[redacted]. The overall price per ton for the Bowie contract increased [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM ([redacted] overall). The Bowie price is higher primarily because of transportation cost escalation. The price per ton for the Castle Valley contract increased [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM ([redacted] overall).

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

A. The arrangement is unchanged from that included in the 2018 TAM. The Castle Valley mine supplies [redacted] tons of coal annually to the Huntington plant. The contract terms contain a mutual right to extend the agreement during an "Option Term" from January 1, 2018, through December 31, 2020, to deliver [redacted] tons per year. The agreement prescribes a calculation for the new 2018 coal price. Based upon the calculation of the 2018 coal price, PacifiCorp exercised its right to extend the agreement through 2020. The estimated 2018 to 2020 Castle Valley coal prices result in a cheaper delivered fuel price when compared with additional coal available under the current long-term coal supply agreement with Bowie.

Coal Supply Agreements for the Jointly Owned Plants

Cholla

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

A. The Cholla plant is supplied under a coal supply agreement with Peabody's Lee Ranch/El Segundo mine complex through 2024. PacifiCorp owns Unit 4, and Arizona Public Service (APS) owns Units 1, 2 (closed October 2015), and 3. PacifiCorp and APS are joint parties to the coal supply agreement that was amended in February 2017. The amendment [redacted] from the original agreement, established fixed amounts related to unrecovered captive mine investment, and capped the January 1, 2018 price re-opener at a [redacted] maximum increase.

Q. What price does the company assume for the Cholla coal supply in the 2019 TAM?

A. PacifiCorp forecasts that the delivered coal price at the Cholla plant will increase [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the current 2019 TAM ([redacted] overall). The coal supply agreement accounts for [redacted] of the increase, partially offset by a rail cost decrease of [redacted]. Of the [redacted], [redacted] is a result of liquidated-damage payments for coal not purchased under the contract due to a [redacted] generation volume reduction at the Cholla plant compared to the 2018 TAM. The balance of the [redacted] is mainly attributable to escalation in diesel fuel and other producer and consumer price indices under the agreement.

The [redacted] rail cost decrease is primarily a result of the new BNSF Railway agreement signed October 2017 that replaced the existing contract that expired at the end of 2017. The new rail agreement is for a two-year term [redacted]. The new rail price negotiated for 2018 is now a fixed price of [redacted] per ton that escalates at [redacted] percent per year plus fuel surcharges. PacifiCorp also negotiated a reduction in the company's minimum annual rail volumes subject to liquidated damages from [redacted] tons to [redacted] tons.

Hayden

Q. Please describe the change in Hayden plant's coal cost in the 2019 TAM.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, an increase of [redacted]. Under the terms of the January 1, 2018 reopener, the coal prices now escalate on a fixed schedule from 2018 to 2022 and are no longer subject to market indices.

Colstrip

Q. Please describe the change in coal cost at the Colstrip plant in the 2019 TAM.

A. Coal prices for the Colstrip plant have increased by [redacted] per ton, from [redacted] per ton in the 2018 TAM to [redacted] per ton in the 2019 TAM, a [redacted] increase. Costs for the Colstrip plant are developed based on Western Energy's Annual Operating Plan (AOP) for the Rosebud mine. The AOP is reviewed and approved annually by the owners of Colstrip Units 3 and 4. The increase in 2019 is primarily attributable to an increase in the Rosebud mine's variable maintenance O&M costs.

SUMMARY

Q. Please summarize the benefits of PacifiCorp's coal fuel strategy.

A. Customers have significantly benefited from PacifiCorp's diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fired generating plants. Several factors have contributed to an overall decrease in coal-fuel expense in this filing, primarily reduced coal volumes. PacifiCorp's fueling strategy has resulted in long-term, stable, low-cost coal supplies for its customers, as demonstrated in Confidential Table 5.

Confidential Table 5: Coal Fuel Variance - 2019 TAM vs. 2018 TAM

Plant	Contract	Millions ($)
Price Variance		
Affiliate Mines		
Jim Bridger	Bridger Coal Company	[redacted]
Craig	Trapper Coal	[redacted]
Subtotal Affiliate Mines		[redacted]
Third-Party Contracts		
Naughton	Kemmerer Coal	[redacted]
Wyodak	Wyodak Coal	[redacted]
Dave Johnston	Powder River Basin Coal	[redacted]
Dave Johnston	BNSF Rail	[redacted]
Jim Bridger	Black Butte Coal	[redacted]
Jim Bridger	UPRR Rail	[redacted]
Hunter	Bowie Coal	[redacted]
Huntington	Bowie and Castle Valley Coal	[redacted]
Cholla	El Segundo Coal	[redacted]
Cholla	BNSF Rail	[redacted]
Colstrip	Rosebud Coal	[redacted]
Hayden	Twentymile Coal and UPRR Rail	[redacted]
Subtotal Third-party Contracts		[redacted]
Total Price Variance		[redacted]
Volume Variance		
Jim Bridger		[redacted]
Cholla		[redacted]
Hunter		[redacted]
Huntington		[redacted]
Naughton		[redacted]
Other Plants		[redacted]
Total Volume Variance		[redacted]
Total Coal Fuel Variance - Increase/(Decrease)		[redacted]

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 339
Exhibit PAC/201
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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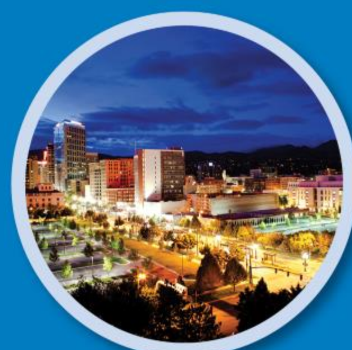
Exhibit Accompanying Direct Testimony of Dana M. Ralston

Long Term Coal Contract Presentation Provided at February 23, 2018 Workshop

March 2018

Workshop on Long Term Coal Contract & Variable O&M in Oregon TAM

February 23, 2018

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Agenda

- Topics from Exhibit PAC/1112 – "Scope of Workshop on Long-Term Coal Contracts and Including Variable O&M in Oregon TAM"
  – 1. PacifiCorp's process by which the terms and conditions of long-term coal contracts are developed, negotiated and approved, and how the company accounts for plant fuel requirements when negotiating long-term contracts or coal mine investment decisions.
  – 2. PacifiCorp's process for managing risk in long-term coal contracts related to: (a) price; (b) contract length; (c) minimum take provisions; (d) liquidated damages; and (e) changing electricity market conditions.
  – 3. How long-term coal contract provisions impact dispatch decisions in GRID, commitment decisions, and long-term system modeling decisions.
  – 4. How (a) long-term coal contracts, (b) fuel transportation contracts, and (c) spot market coal fuel purchases are each reviewed before the Public Utility Commission of Oregon.
  – 5. The potential development of a method to reflect variable O&M in NPC, including classification of which O&M costs should be treated as variable and the treatment of variable O&M in rates.
- Coal plant economic cycling modeling (See Order No. 17-444 at 11)

1. Long Term Coal Contract Process

- What is PacifiCorp's process by which the terms and conditions of long term coal contracts are developed, negotiated and approved; and how does the company account for plant fuel requirements when negotiating long term contracts or coal mine investment decisions?

1. Long Term Coal Contract Process (cont'd)

- The budget/business plan which is used to determine fuel requirements for the plants. Once the requirements are determined, the fuels group uses that information to develop coal portfolios that minimize costs, but still allow some degree of upward/downward flexibility for changing market conditions.
- The following slides will review the factors PacifiCorp considers when negotiating and developing coal & transportation contracts.

1. Long Term Coal Contract Process (cont'd)

- PacifiCorp's process in developing & negotiating long term contracts considers and evaluates the following factors;
  - Plant location/coal regions
  - Coal supply options
  - Coal transportation options
  - Coal quality constraints
  - Other market alternatives
- Proposals are evaluated on a least cost/least risk basis
- Term vs. Volume vs. Price

1. Long Term Coal Contract Process (cont'd)

- Background information on PacifiCorp owned and operated plants
  - Each plant is located in a specific coal region with unique opportunities & constraints
    - » Wyoming PRB Region Plants
      - Wyodak
      - Dave Johnston
    - » SW Wyoming Region Plants
      - Jim Bridger
      - Naughton
    - » Utah Region Plants
      - Hunter
      - Huntington

1. Long Term Coal Contract Process (cont'd)

- Regional Coal Supply Options
  - » Wyoming PRB Region
    - Largest coal production region in the country (over 300m tons annually)
    - Large mines with very favorable stripping ratios & mining conditions
    - Multiple competing & active mines (Six coal companies – 13 active mines)
    - Consistent coal quality (8800 Btu/lb.; 8400 Btu/lb. and 8000 Btu/lb.)
    - Both Union Pacific and BNSF railroads have access to the PRB

1. Long Term Coal Contract Process (cont'd)

» SW Wyoming Region
- Three operating mines (Three coal companies – 11m tons annually)
- More difficult mining conditions (higher strip ratio, multiple seams)
- Coal quality can be inconsistent

» Utah Region
- All deep underground mines
- Six operating mines (Four coal companies – 12m tons annually)
- Only three longwall operating mines
- Underground mining is very challenging with complex geology
- Utah coal is actively exported

1. Long Term Coal Contract Process (cont'd)

- Coal Transportation
  - Wyodak plant
    - » Mine mouth – conveyor belt (No unloading facilities)
  - Dave Johnston plant
    - » Rail deliveries
      - Captive to BNSF Railroad
  - Jim Bridger plant
    - » Mine mouth – Bridger Coal Company – conveyor belt
    - » Rail deliveries
      - Captive to Union Pacific railroad for coal deliveries from outside sources
  - Naughton plant
    - » Mine mouth – conveyor belt (No unloading facilities)
  - Hunter plant
    - » Truck deliveries – no rail unloading facilities
  - Huntington plant
    - » Truck deliveries – no rail unloading facilities

1. Long Term Coal Contract Process (cont'd)

- Coal Quality Constraints
  - Plants were originally designed to consume coal from regional coal sources
  - Additional plant capital may be required in order to consume coal from different regions depending upon coal quality & delivery methods
- Other Market Alternatives
  - Factors impacting market alternatives

Coal Region
- Supply/Demand
- Number of coal suppliers available
- Liquid vs. illiquid markets
- Coal supplier's operating history
- Supplier's financial strength

Transportation options
- Mine mouth – conveyor belt
- Rail v. Truck
  - Tonnage volumes
  - Total distance from coal supply to plant
  - New capital requirements for fuel switch

1. Long Term Coal Contract Process (cont'd)

- PacifiCorp utilizes different types of contract structures with differing contract lengths (spot 1-yr; near term <5 yrs; & long term) for each plant
  - Dave Johnston – Contract Portfolio
    - Wyoming PRB Coal Region
    - Multiple spot/near term contracts (1 - 4 years)
    - Contracts are staggered
    - RFP process is typically conducted annually
    - This provides a hedge against price volatility

1. Long Term Coal Contract Process (cont'd)

- Wyodak – Long Term Contract
  - Wyoming PRB Coal Region
  - Plant is captive to the Wyodak mine
  - Plant receives coal via a conveyor belt
  - No coal unloading facilities
  - No plant stockpile
  - Index based contract with periodic market price reopeners

1. Long Term Coal Contract Process (cont'd)

- Naughton – Long Term Contract
  - SW Wyoming Coal Region
  - Captive to the Kemmerer mine
  - Plant receives coal via a conveyor belt
  - No coal unloading facilities
  - Index based contract with periodic market price reopeners

1. Long Term Coal Contract Process (cont'd)

- Jim Bridger – Mix of Mine Mouth & Near Term Contract
  - SW Wyoming Coal Region
  - Plant receives Bridger Mine coal via a conveyor belt
  - Plant also receives coal from nearby Black Butte Mine
  - Black Butte coal is shipped via rail and is captive to Union Pacific railroad
  - Black Butte contract is a near term (4 year) agreement
  - Black Butte contract is a fixed priced agreement

1. Long Term Coal Contract Process (cont'd)

- Hunter – Long Term Contract
  - Utah Coal Region
  - Plant has been fueled with both long term & near term contracts
  - All coal deliveries to the plant are shipped via 42-ton coal haul trucks
  - There is no rail unloading facility
  - The long term contract allows for qualified "substitution" coal if needed

1. Long Term Coal Contract Process (cont'd)

– Huntington – Long Term Contract

- Utah Coal Region
- Plant is fueled with long term contracts
- All coal deliveries to the plant are shipped via 42-ton coal haul trucks
- There is no rail unloading facility
- The long term contract allows for qualified "substitution" coal if needed

1. Long Term Coal Contract Process (cont'd)

- Individual plant fuel requirements are derived from PacifiCorp's budget which provides:
  - Total generation & total MMBtus
    - Fuel Resources determines the estimated annual consumed tonnage requirements based on the budget results from GRID for each plant taking into account the plant's inventory level and the ability to have some degree of upward/downward flexibility

1. Long Term Coal Contract Process (cont'd)

- Contract Approval Process
  - Coal & transportation agreements are reviewed by internal legal & credit/risk departments
  - The approval authorization signature of each contract is in accordance with PacifiCorp's governance policies
    - Total dollar value of each agreement is determined and is then directed to the PacifiCorp executive with the authorized approval limits

2. Managing Risk

- What is PacifiCorp's process for managing risk in long term coal contracts related to (a) price; (b) contract length; (c) minimum take provisions; (d) liquidated damages; and (e) changing electricity market conditions?

2. Managing Risk (cont'd)

- PacifiCorp's strategy is to contract for as short of term as possible while taking into account the risk associated with supply, volume & price. PacifiCorp seeks to find a "balanced outcome" between contract term, contract price and contract volume.

2. Managing Risk (cont'd)

– PacifiCorp manages pricing risk through one or more of the following, dependent upon location:

- Fixed priced agreements
- Tiered pricing agreements
- Price reopener provisions
- Capped market price reopener pricing provisions
- Indexed pricing agreements

2. Managing Risk (cont'd)

- Contract length is managed by:
  - Determining the proper length which includes evaluating & managing pricing & supply risk
  - Contract extension options
  - Contract termination provisions
  - Future plant retirement dates
- Minimum take provisions are managed by:
  - Nomination provisions
  - Minimum/Maximum tonnage provisions
    - Tonnage flexibility
    - Percentage take flexibility
    - Shortfall/Pre-delivery provisions
    - Re-sell rights

2. Managing Risk (cont'd)

- Liquidated damages (LDs) are used:
  - Avoid "take or pay" payments
    - LDs are a small percentage payment of the total price
  - Protect PacifiCorp with "environmental out" provisions
  - LDs can be used to control the plant's total inventory
- PacifiCorp manages changing electric market conditions
  - Length of contracts
  - Specific contract structure
    - Tiered pricing provisions
    - Minimum take requirements
  - Flexing plant stockpile inventory levels

3. GRID Impacts of Long Term Coal Contracts

- How do PacifiCorp's long term coal contract provisions impact dispatch decision in GRID?

3. GRID Impacts of Long Term Coal Contracts (cont'd)

- The coal contracts inform the coal costs used in the TAM and are an input to the GRID model.
- GRID uses two tiers for its thermal resources:
  - **Dispatch Tier:** The incremental coal price, along with resource attributes and heat rates, is used by GRID to determine dispatch.
    - Incremental coal price of contract coal is calculated based on the terms of the contract which may include minimum take requirements/liquidated damages.
    - Incremental coal price of coal from Company-owned mines is determined by the operating cost required to produce the next ton of coal.
  - **Costing Tier:** The average cost of the total coal tonnage in the forecast period and is applied to the coal volumes as determined by GRID, and are reported in the net power costs (NPC) results as total coal fuel burn expense.

4. PUC Review

- How are PacifiCorp's long term coal and transportation contracts each reviewed before the Public Utility Commission of Oregon?
  - Commission and Staff reviews company provided fuel costs information through regular Oregon TAM and PCAM filings
  - Review of these agreements are protected under confidentiality provisions

5. Variable O&M and NPC

- What is PacifiCorp's recommended method to reflect variable O&M costs in NPC, including the classification of which O&M costs should be treated as variable and the treatment of variable O&M in rates?

5. Variable O&M and NPC

- PacifiCorp will begin including variable O&M in the incremental coal (coal) price.
- PacifiCorp will not seek to include variable O&M in the TAM and PCAM.

Economic Cycling of Coal Units

The Company proposes to model the economic cycling of coal plants.

- The criteria for economic cycling candidates are:
  - The unit is majority owned by the Company
  - The unit is NOT an EIM participating unit
  - The unit is not under operational constraints

Economic Cycling of Coal Units (cont'd)

- Cycling Period is Generally February 1 to May 31
  - Loads are generally lower in the spring
  - Weather is typically mild
  - Spring runoff for hydro
  - Generally lower market prices
  - Solar imports from California are ramping up

Economic Cycling of Coal Units (cont'd)

- GRID will determine coal dispatch
- The following will be considered in the economic dispatch:
  - Start-up costs and start-up duration, varies by plant
  - Minimum downtime of one week
  - Number of cycles during the cycling period is limited to four
  - Take-or-pay provisions/liquidated damages

Questions?

REDACTED
Docket No. UE 339
Exhibit PAC/202
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

PacifiCorp Coal Inventory Policies and Procedures – Updated March 20, 2018

March 2018

This exhibit is highly confidential in its entirety. Availability of this document is restricted to individuals who have signed the Modified Protective Order in Docket UE 339.

REDACTED
Docket No. UE 339
Exhibit PAC/203
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

Coal Inventory Study – Prepared by RPM Global – March 19, 2018

March 2018

This exhibit is highly confidential in its entirety. Availability of this document is restricted to individuals who have signed the Modified Protective Order in Docket UE 339.

REDACTED
Docket No. UE 339
Exhibit PAC/204
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

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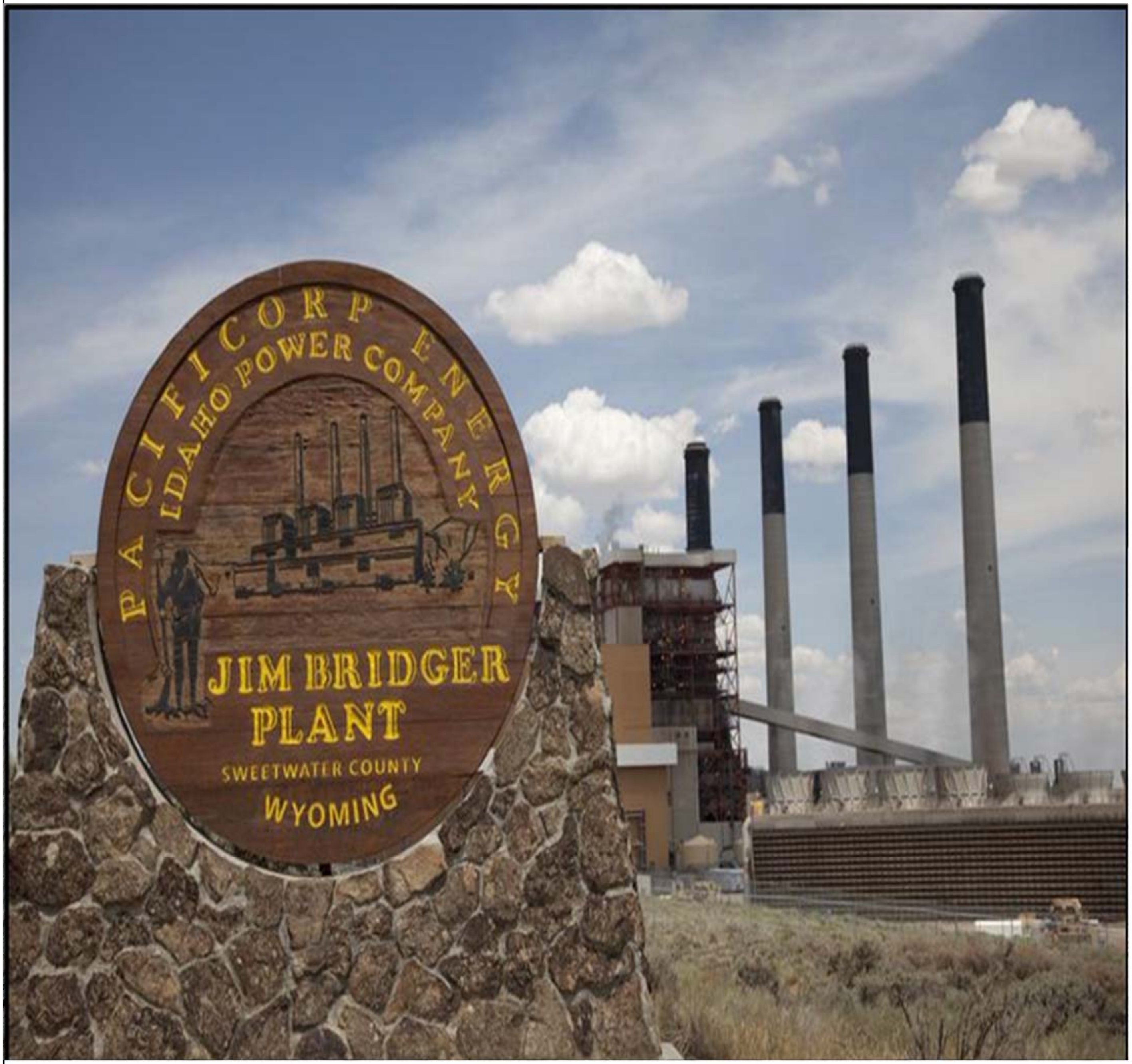
REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

PacifiCorp Long-Term Fuel Supply Plan for the Jim Bridger Plant – March 2018

March 2018



PACIFICORP CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT

March 2018

PACIFICORP
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CONTENTS

1 INTRODUCTION AND EXECUTIVE SUMMARY

In the final order in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, Order No. 13-387, the Public Utility Commission of Oregon (Oregon Commission) adopted PacifiCorp's proposal to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives. In December 2015, PacifiCorp complied with Order No. 13-387 by providing "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" (2015 Fuel Plan). Subsequently, PacifiCorp committed in testimony to provide periodic updated filings to the 2015 Fuel Plan. In its orders in the 2017 and 2018 TAMs, the Oregon Commission directed PacifiCorp to hold workshops to discuss information and analyses required to meaningfully evaluate long-term fueling plans for the Jim Bridger plant. To date, three different workshops have been held with the Oregon staff and intervenors to discuss various details and assumptions associated with the development of the updated PacifiCorp Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant (2018 Fuel Plan).

As set forth in PacifiCorp's compliance filing in docket UE 287, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, least-risk coal supply evaluated on a multi-year basis. The long-term fuel supply plan is designed to ensure that fuel supplies are fair, just and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

Additionally, PacifiCorp agreed to provide a long-term fueling strategy for the Jim Bridger plant in the stipulation Settlement Agreement to the 2015 Wyoming Energy Cost Adjustment Mechanism (ECAM) filing (docket 20000-472-EA-15). The evaluation would include coal supply pricing, transportation and modifications to the plant for an alternative fuel supply. The report would be updated periodically to address significant milestones.

To develop the 2018 Fuel Plan, PacifiCorp has studied, reviewed and evaluated different fueling options for the Jim Bridger plant. For the 2018 Fuel Plan, the annual generation requirements expressed in consumed tons were derived from PacifiCorp's budget which is calculated using PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) model[1]. The generation requirements derived from the GRID model have also been used for the basis of PacifiCorp's 2017 Integrated Resource Plan (IRP) Update. Within the 2018 Fuel Plan, different fueling options are presented. The fueling options consider varying tonnage delivery schedules sourced from Bridger Coal Company (Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB), which are "8,800" Btu/lb. mines. Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified tonnage delivery schedules from both the underground and surface mining operations. Included in these different mine scenarios are estimated shutdown dates for Bridger mine's underground and surface operations. The 2018 Fuel Plan provides third party coal supply tonnages and pricing estimates based upon recent negotiations, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2018 Fuel Plan provides estimated tonnage volumes and rail rates for transportation services provided by the Union Pacific Railroad for the transport of coal from third party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are presented in a detailed third party study completed in 2017 by the engineering and consulting firm Burns & McDonnell.

[1] The GRID model used for budget purposes is different than the GRID model used in the Oregon TAM. The budget GRID model is used to determine the net power cost budget, but is not subject to the same normalizing and regulatory modeling constraints as the GRID model used in the Oregon TAM.

After considering all of the factors influencing long-term fueling strategy, the Company developed and evaluated six different Jim Bridger plant fueling options. A Present Value Revenue Requirement (PVRR) calculation was completed for the various fueling options and includes a composite ranking considering both financial and risk weighting. Based upon the results of the detailed PVRR analysis and utilizing a risk profile, Option F ([redacted]) is the current least-cost, least-risk option. While the current analyses shows Option F as the least-cost, least-risk option, Option D is the lowest cost option and will continue to be analyzed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking in to consideration both cost and risk of the different options and will change the long-term fuel supply plan as necessary to provide the least-cost, least-risk fuel supply for the Jim Bridger plant.

The benefits of pursuing Option F as the long-term fueling strategy for the Jim Bridger plant include the following:

- [redacted]
- [redacted])
- [redacted]
- [redacted]
- [redacted]
- [redacted]

2 BACKGROUND

The Jim Bridger plant is a four unit coal-fired plant located in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of Rock Springs, Wyoming.

The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7%) and Idaho Power Company (Idaho Power) (33.3%). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Over the past two years, Jim Bridger plant has consumed approximately 6.6 million tons of coal per year. From 2006 to 2015, the Jim Bridger plant consumed on average 8.0 million tons per year. The plant is designed to burn coal sourced from southwest Wyoming with heat content in the range of 9,000 Btu/lb. to 10,000 Btu/lb. The depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states based on PacifiCorp's 2012 depreciation study.

The Bridger mine is located adjacent to the Jim Bridger plant. The Bridger mine includes both surface and underground mining operations and, similar to the Jim Bridger plant, is jointly owned by PacifiCorp (66.7%) and Idaho Power (33.3%). The surface operation consists of a combination dragline and truck/loader operation that produces approximately [redacted] million tons of coal per year. Bridger mine's underground operation uses continuous miners and longwall mining equipment to produce coal. The underground mine produces approximately [redacted] million tons of coal per year. The coal is transported from both the underground and surface mining operations to surface stockpiles or directly to the Jim Bridger plant via a nine mile overland conveyor system.

For regulatory purposes, Bridger mine is consolidated with PacifiCorp's operations. PacifiCorp's share of Bridger mine is included in the PacifiCorp rate base and its share of mining costs, including depreciation and depletion, is included in net power costs.

In addition to the estimated [redacted] million tons of coal forecast to be delivered annually from the Bridger mine to the Jim Bridger plant, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements, approximately [redacted] million tons per year, from the nearby Black Butte mine. The Union Pacific Railroad provides rail access for all the coal delivered from the Black Butte mine to the plant.

3 ASSUMPTIONS

The 2018 Fuel Plan for the Jim Bridger Plant was prepared in two phases. The key variables used in the plan were subject to in-depth review and study. These assumptions are explained below:

3.1 EVALUATION – PHASE 1

3.1.1 Generation

Generation assumptions are taken from PacifiCorp's budget GRID model and parallel PacifiCorp's 2017 IRP Update which will be submitted in May 2018, and are used in all evaluated alternatives. Consistent with the findings of the IRP, the 2018 Fuel Plan assumes the closure of Jim Bridger Unit 1 on December 31, 2028, and Jim Bridger Unit 2 on December 31, 2032. These assumptions represent a significant change from the assumed generation requirement used to evaluate the plant's fueling needs in the 2015 Fuel Plan. This plan assumed a total plant annual consumption of [redacted] million tons through the life of the plant.

Consistent with the IRP, coal consumption is shown to decline through 2037, the depreciable plant life. The assumed burn level is approximately [redacted] million tons per year for 2018 through 2022; approximately [redacted] million tons per year for 2023 through 2028; approximately [redacted] million tons per year for 2029 through 2032; and approximately [redacted] million tons per year through 2037. The assumed generation levels between the 2015 and 2018 Fuel Plans are compared in Appendix A.

3.1.2 Plant Depreciable Life

The assumed depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states, based on PacifiCorp's 2012 depreciation study.

3.1.3 2015 Fuel Plan –"Base Operating Plan"

The 2015 Fuel Plan recommended fueling the plant under the Base Operating Plan. This plan consisted of the following main elements:

- Continued surface mining at Bridger mine through [redacted]
- Permitting and mining the Deadman Wash tract at Bridger mine
- Closure of the Bridger mine underground operations in [redacted] – remaining inventory delivered in [redacted]
- Continued purchase of Black Butte mine coal through [redacted]
- Conversion of the Jim Bridger plant to SPRB coal deliveries requiring estimated capital expenditures of [redacted] million (PacifiCorp share)
- [redacted] SPRB deliveries, replacing Black Butte coal deliveries, begin in [redacted] and continue through [redacted]
- Infrastructure improvements begin in [redacted] with infrastructure fully in place and operable by [redacted]

As mentioned above, the Base Operating Plan was recommended based on the assumption that Jim Bridger plant consumption would be between [redacted] and [redacted] million tons per year (total plant). Actual plant coal consumption for 2016 and 2017 was significantly less than the assumed consumption. Total coal consumption at the plant was [redacted] than expected in the Base Operating Plan over the two-year period as shown in Table 1.

TABLE 1

"Base Operating Plan" - 2015 Long-Term Fuel Supply Plan for the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
Actual Tonnage Consumed at the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
Variance in Tonnage Consumed at the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
% Change						

The significant decrease in forecasted consumption required revisions to the recommended Base Operating Plan. [redacted] Effective March 2017, the Base Operating Plan was modified to include this change.

3.1.4 Further Refinement of the "Base Operating Plan"

In addition to the change mentioned above, an additional step was taken to further optimize the Base Operating Plan by determining the optimal closure plan for the Bridger mine underground mining operation. Bridger mine prepared four, [redacted] mine plans with varying underground closure dates. The mine production volume target was based on estimated consumption and purchases of third party coal. The four plans are summarized below:

- Underground Mine Option A –
    - Underground closure in [redacted]
    - Surface closure in [redacted]
- Underground Mine Option B –
    - Underground closure in [redacted]
    - Surface closure in [redacted]
- Underground Mine Option C –
    - Underground closure in [redacted]
    - Surface closure in [redacted]
- Underground Mine Option D –
    - Underground closure in [redacted]
    - Surface closure in [redacted]

Bridger mine's underground operations experienced a significant challenge with the mine's western reserves in 2015 and 2016. Based on knowledge gained from this experience, the Bridger mine reduced planned production in the area and accelerated the move to the mine's eastern reserves. Ultimately Underground Mine Option D with the underground closure in [redacted], emerged and was found to be the least-cost, least-risk option. Table 2 compares the results of the analysis in terms of (PVRR):

TABLE 2

PVRR Summary		
PVRR Summary (PacifiCorp Share)	PVRR (000's)	Differential (from lowest $)
[redacted]		
Financial Ranking & Operation Risk Ranking		
PVRR Summary (PacifiCorp Share)	Financial Ranking (low to high)	Operation Risk Ranking (low to high)
[redacted]		

The results of this analysis were presented to Oregon Commission staff in a workshop held March 1, 2017. The analysis established the Base Operating Plan as modified, consistent with Underground Mine Option D above as the new baseline for continued evaluation.

Underground Mine Option D – The March 2017 Base Operating Plan consists of the following main elements:

- Continued surface mining at Bridger mine through [redacted]
- Permitting and mining the Deadman Wash tract at Bridger mine
- Closure of Bridger mine underground operations in [redacted]
- Continued purchase of Black Butte mine coal through [redacted]
- SPRB coal deliveries from [redacted] continuing through [redacted] in quantities which will not require significant capital modifications at the plant

3.2 EVALUATION – PHASE 2

3.2.1 Economic closure of the Bridger mine surface operation

With the March 2017 Base Operating Plan established and the underground mine closure date determined, Bridger mine prepared three, [redacted] million ton per year mine plans. This level of production complemented expected future total plant consumption of [redacted] million tons per year and third party purchases. One of the options also considered was a complete conversion to SPRB deliveries as soon as practicable. The three mine plans are summarized as follows:

- Surface Mine Option D –
  - Underground closure in [redacted]
  - Surface closure in [redacted]
- Surface Mine Option E –
  - Underground closure in [redacted]

    - Surface closure in [redacted]
- Surface Mine Option F –
    - Underground closure in [redacted]
    - Surface closure in [redacted]

The revised Surface Mine Option D mine plan maintained assumptions consistent with those described above for the March 2017 Base Operating Plan, except the assumed Bridger mine production level was reduced to reflect deliveries of [redacted] million tons per year from the [redacted] million tons per year level mentioned previously.

A fueling plan option based on Bridger mine's Surface Mine Option E mine plan assumed a complete conversion to the consumption of SPRB coal following the closure of both underground and surface mining operations at Bridger mine in [redacted]. A complete conversion was not possible prior to [redacted], due to the capital modifications required at the Jim Bridger plant to safely and reliably receive and consume SPRB coal in large volumes. As a result, the fueling options have been separated into "near-term" and "long-term" periods for discussion purposes. For purposes of the 2018 Fuel Plan, the near-term period has been defined as the next three-to-four years and corresponds to the estimated time required to design, procure and construct the capital infrastructure to successfully unload trains and consume coal originating in the SPRB.

Surface Mine Option F further developed Surface Mine Option D. The key change was the assumption of [redacted], avoiding [redacted] million ([redacted] million PacifiCorp share) in development costs, and closure of the Bridger mine surface mining operation in [redacted]. After closure of the Bridger mine surface mining operation, Surface Mine Option F supplements the Bridger mine deliveries with coal from both the [redacted].

3.2.2 Third Party Coal

Based on the location of the Jim Bridger plant, economic fuel supply alternatives are limited to two operating mines located in southwest Wyoming and the SPRB mines of Campbell County, Wyoming.

The Black Butte mine, 20 miles southeast of the Jim Bridger plant, is jointly owned by Lighthouse Resources Inc. (Lighthouse) and Anadarko Petroleum. Operated by Lighthouse, the mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck/loader fleet. Historically, Black Butte mine has mined approximately 3.5 to 4.0 million tons per year, a significant portion of which has supplied the Jim Bridger plant. However, one of Black Butte mine's significant contracts has expired. The mine is now producing less than [redacted] million tons per year and the Jim Bridger plant is the mine's only customer. During 2016 and 2017, the Jim Bridger plant received approximately one-third of its fuel supplies from the Black Butte mine under a contract that will terminate in [redacted]. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with the Union Pacific Railroad.

The other southwest Wyoming mine is Westmoreland's Kemmerer mine. In 2017, Westmoreland purchased the idled Haystack mine located 30 miles south of the Kemmerer mine. Presently the Kemmerer mine supplies PacifiCorp's Naughton plant and southwest Wyoming's trona (soda ash) industry. The Kemmerer mine coal is delivered to customers via overland conveyor, truck transportation and limited rail operations. Presently the Kemmerer mine's rail loading infrastructure is incapable of loading a full unit train efficiently. In addition, the grade elevation surrounding the mine requires additional locomotives to power a full unit train. As a result, the mine very rarely loads full unit trains. Given the Kemmerer mine's current rail loading infrastructure, rail delivery of coal would only be viable on a limited scale. Delivery of a sizable volume of Kemmerer coal to the Jim Bridger plant would require more costly truck transportation. [redacted].[2]

The Powder River Basin is the largest coal mining region in the United States. Coal from the SPRB is classified as sub-bituminous coal. SPRB coal contains an average heat content of approximately 8,800 Btu/lb. The coal mined in the SPRB is low sulfur and low ash. Due to its unique quality characteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In 2017, there were eight different mining companies operating fourteen active mines in the Powder River Basin, producing roughly 300 million tons. SPRB mines contain the highest heat content coal ranging between 8,600 Btu/lb. and 8,950 Btu/lb. These mines are located about 550 miles from the Jim Bridger plant.

SPRB mines are served by the Union Pacific Railroad and Burlington Northern Santa Fe Railway railroads. Both of these railroads have joint access to all of the mines located south of Gillette, Wyoming, in the SPRB.

3.2.3 Black Butte Pricing

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[2] See footnote [redacted].

TABLE 3

CONTRACT PROPOSALS - ANNUAL VOLUME & PRICING					
Proposal A	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal B	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal C	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal D	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal E	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					

REDACTED

The least-cost, least-risk option for the near-term was identified by comparing the cost of purchasing incremental volume from Black Butte mine to the cost of producing incremental volume at Bridger mine. The comparison consisted of the following two options:

1. [redacted] (Black Butte mine Proposal A)

2. [redacted] (Black Butte mine Proposal D)

Other options were considered and evaluated, but were found to not be economically viable. Specifically, an option considering Bridger mine deliveries at [redacted] million tons per year and Black Butte mine deliveries at [redacted] million tons per year is discussed in the following pages.

The Company ultimately selected Black Butte mine's Proposal A as the least-cost, least-risk coal supply option for the near-term. Proposal A preserves flexibility to further assess and implement long-term fuel options before making any long-term, large capital investments. Table 4 details the delivered cost savings of [redacted] million to PacifiCorp from purchasing coal under the selected option:

TABLE 4

PacifiCorp Share						
[redacted] (Black Butte Mine - Proposal A)						
Mine	*2018*	*2019*	*2020*	*2021*	*2022*	*Total*
Bridger Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Black Butte Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
$/Ton						
Rail Rate $/Ton						
Total Coal Dollars						
Total Rail Dollars						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Total Deliveries						
Tons						
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
[redacted] (Black Butte Mine - Proposal D)						
Mine	*2018*	*2019*	*2020*	*2021*	*2022*	*Total*
Bridger Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Black Butte Mine						
Tons						
Btu/lb						
Mmbtus						
$/Ton						
Rail Rate $/Ton						
Total Coal Dollars						
Total Rail Dollars						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Total Deliveries						
Tons						
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
VARIANCE						
	2018	*2019*	*2020*	*2021*	*2022*	*Total*
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Calculation of Price Savings - [redacted]						
MMBtu Delivered Variance						[redacted]
*Multiplied by [redacted] (Proposal D) MMBtus						
Price Savings						

Concurrent negotiations were held with Union Pacific Railroad for coal transportation from the Black Butte mine. The delivered costs shown in the above Table 4 includes rail transportation rates consistent with the negotiations. The estimated savings shown in the table represents PacifiCorp's share of the total savings.

Upon the expiration of the near-term 2018 contract with Black Butte mine, the pricing for Black Butte mine coal is assumed to increase at [redacted] per year.

3.2.4 Powder River Basin Coal in the Near-Term

Powder River Basin coal has a high propensity to spontaneously combust, and is the most friable coal type burned in the power industry. While major plant modifications would be required to safely and reliably receive and consume large volumes of SPRB coal at the Jim Bridger plant, the plant is likely capable of consuming SPRB coal on a limited scale without major modification to the plant's coal unloading or coal consuming infrastructure. For example, in a test burn in 2015, the plant handled and consumed 10 trains totaling 140,540 tons of SPRB coal. Based on knowledge gained from the test burn and PacifiCorp's professional judgement, plant management believes that up to [redacted] tons of SPRB coal per year might be safely and reliably consumed without major modifications to the plant. This estimate is considered to be aggressive.

PacifiCorp considered the possibility of reducing the amount of coal purchased from the Black Butte mine and purchasing a small amount, up to [redacted] tons (PacifiCorp share), from a SPRB coal mine on an annual basis. As shown in Table 5, the purchase of small volumes of SPRB coal was not the least-cost option.

For example, PacifiCorp has chosen to purchase [redacted] tons per year[3] of incremental coal from Black Butte mine under Proposal A, [redacted]. PacifiCorp has also chosen to forego the purchase of [redacted] tons per year of coal from Bridger mine (or SPRB coal) that would have been required if Black Butte mine Proposal D, [redacted], had been elected. Average costs for the [redacted] annual incremental ton variances can be derived from the proposals and mine plans outlined in Table 4 and are shown for both the Black Butte mine and Bridger mine in Table 5. The estimated average delivered cost of [redacted] tons of SPRB coal is also shown. On a delivered \$/MMBtu basis, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] than the delivered cost of Black Butte mine's incremental coal [redacted] over the term of the proposals. In addition, the estimated delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] over the four year term than the incremental cost of coal mined at the Bridger mine [redacted].

As shown in Table 5, this relationship also holds when comparing deliveries under Black Butte mine Proposal A and Black Butte mine Proposal B, [redacted]. If Proposal B was chosen, PacifiCorp would forego the purchase of [redacted] tons of the [redacted] total incremental tons available under Black Butte mine Proposal A. On a delivered \$/MMBtu basis, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] than the delivered cost of Black Butte mine's incremental coal [redacted] over the term of the proposals. In addition, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] over the four year term than the incremental cost of coal mined at the Bridger

[3] Represents PacifiCorp's share of the [redacted] differential between Proposal A and Proposal D (difference between [redacted])

mine [redacted]. The concept of PacifiCorp purchasing fewer tons from Black Butte mine and replacing that volume with a small amount, from [redacted] tons up to [redacted] tons, of SPRB coal (or coal from Bridger mine) was eliminated in the near-term based on these findings.

PacifiCorp also considered accepting Black Butte mine Proposal B, [redacted], and simultaneously [redacted] Bridger mine deliveries by [redacted] tons per year to [redacted] million tons per year, on a total mine basis. Based on data shown in Table 5, in accepting Proposal B, PacifiCorp would purchase [redacted] tons of the [redacted] total incremental tons available from Bridger mine at an [redacted] premium over the cost of purchasing the coal from Black Butte mine. As a result, PacifiCorp chose to forego the purchase of [redacted] tons from the Bridger mine at an incremental cost of [redacted] in favor of purchasing the [redacted] incremental tons from Black Butte mine at an incremental cost of [redacted].

TABLE 5

Incremental Cost For Black Butte Proposal Term

		SPRB	Bridger	Black Butte (Prop. A - Prop. D)	Black Butte (Prop. A - Prop. B)
Coal	$	[redacted]			
Freight	$				
$/Ton	$				
Btu/lb					
$/mmBtu	$				[4]

3.2.5 Black Butte Mine Volume

PacifiCorp conducted a high-level review of the Lighthouse Resources Inc. Black Butte mine coal resource and reserve estimates in 2015. The study consisted of reviewing available third-party Black Butte reserve and geology documents, along with Black Butte's geology information and permitting status. At the time, based on the information reviewed, the conclusion of the review was that Black Butte mine had [redacted] million tons that could be considered economic coal reserves under the terms and conditions of the then-current contract.

For assumed Black Butte mine production in the 2018 Fuel Plan, PacifiCorp has updated these reserve estimates. The estimated reserves have been [redacted] since the date of the 2015 reserve review, and have [redacted] based on discussions with Lighthouse [redacted] As of that date, Black Butte mine claimed permitted reserves of [redacted]

[4] Consistent with Table 4, incremental prices shown are weighted over the near-term, with exception of the SPRB pricing. SPRB prices are averaged over four years with equal annual volumes.

- 2018 Fuel Plan Option D – [redacted]
- 2018 Fuel Plan Option F [redacted]
- 2018 Fuel Plan Option F – [redacted]

3.2.6 Assumed SPRB Coal Pricing

Due to the Jim Bridger plant's distance from the SPRB, roughly 550 miles by rail, the Jim Bridger plant would source SPRB coal from the mines with the highest heat content (Btu/lb.) The economics of the purchase decision would target coal originating from three mines in the SPRB, Cloud Peak Energy Resources LLC's Antelope mine, Peabody COALSALES, LLC's North Antelope Rochelle Mine and Arch Coal Sales Company Inc.'s Black Thunder mine. These mines typically sell coal on an 8,800 Btu/lb. basis as opposed to other areas of the Powder River Basin that sell 8,400 Btu/lb. or lesser heat content coals.

The Powder River Basin is the largest coal mining region in the United States. As a result, standard 8,800 Btu/lb. and 8,400 Btu/lb. Powder River Basin coal is routinely traded, indexed and forecast. Assumed SPRB coal pricing used in the 2018 Fuel Plan is based on a long-term coal forecast published by EVA in September 2017.

3.2.7 Transportation

Bridger mine coal is delivered to the plant via conveyor belt, and the cost of conveying the coal is included in the delivered coal cost. The Jim Bridger plant is also connected by a rail spur to the Union Pacific Railroad mainline track. Union Pacific Railroad has the trackage rights to the mainline and spur to the Jim Bridger plant and, as a result, the Jim Bridger plant is captive to the Union Pacific Railroad for deliveries by rail. Deliveries from all sources other than Bridger mine are assumed to be delivered by the Union Pacific Railroad.

UNION PACIFIC RAILROAD INDICATIVE PRICING

Early in 2017, PacifiCorp requested that Union Pacific Railroad provide indicative rates to aid in evaluating increased SPRB coal deliveries to the Jim Bridger plant with an estimated start-up in [redacted]. PacifiCorp requested rates for deliveries ranging from [redacted] million tons per year. To better understand potential price discounts for added volume, rates for deliveries in both PacifiCorp and Union Pacific Railroad railcars were requested at various volume levels in the [redacted] per year range.

Union Pacific Railroad provided indicative rates in June 2017. The rates applied to the volume range previously specified, from [redacted] per year up to [redacted] per year and were provided in current dollars. However, Union Pacific Railroad did not provide information on volume discounts for specific volume ranges as requested, nor did Union Pacific Railroad provide specific rates for deliveries in PacifiCorp or Union Pacific Railroad railcars. Instead, it provided an estimated freight rate for planning purposes in the range of [redacted] per net ton, which included railroad owned railcars, but excluded a fuel component and quarterly escalation.

UNION PACIFIC RAILROAD CONTRACT PRICING

In 2017, while negotiations took place with Black Butte mine for near-term coal supplies, near-term rail transportation negotiations were also conducted with Union Pacific Railroad. Similar to the Jim Bridger plant, the Black Butte mine is connected by a rail spur to Union Pacific Railroad's mainline track. Negotiations with Union Pacific Railroad concluded with a signed contract in February 2018. The transportation agreement includes the following key provisions as of January 1, 2018:

- Minimum volume: [redacted]
- Maximum volume: [redacted]
- Rail rates provided for shipments from:
  - Lighthouse's Black Butte mine - [redacted]
  - Wyoming's SPRB region - [redacted]
  - Westmoreland Kemmerer, LLC's Kemmerer mine located in Lincoln County, Wyoming - [redacted]
  - Peabody's Twentymile mine located in Routt County, Colorado - [redacted]
- All rates subject to escalation and fuel surcharge

USE OF INDICATIVE AND CONTRACT PRICING

For SPRB deliveries, the lower end of the indicative rate range, [redacted] per ton, is used as of January 1, 2018, in any fueling option where more than [redacted] per year are delivered to the plant. This rate is then escalated at [redacted] (provided by IHS/Global Insights in Q3 2017) per year thereafter.

When SPRB deliveries are less than [redacted] per year, the contract rate is applied. For example, a [redacted] per ton contract rate is used as of January 1, 2018, in fueling options where only small volumes of SPRB coal is delivered to the plant. This rate is also escalated at a rate of [redacted] per year thereafter.

PacifiCorp owns 121 aluminum bottom-dump railcars with a net payload of 105 tons per car. Consistent with current operating practice for Black Butte mine deliveries, the [redacted] per ton rate is used and is escalated at a rate of [redacted] per year.

3.3 CAPITAL

PacifiCorp selected the consulting firm Burns & McDonnell (BMcD) to perform an independent capital evaluation of the plant modifications and capital expenditures required at the Jim Bridger plant to consume volumes, up to 100%, of SPRB coal. BMcD completed a comprehensive study in June 2017. The study outlined high priority plant modifications and the estimated costs in converting the Jim Bridger plant's main fuel source to SPRB coal. The study focused on required modification to several systems including coal handling & storage, rail delivery, mechanical process/power island, electrical, substation and overhead distribution and air permitting.

The required coal handling system modifications identified engineering controls that would be needed and relied upon to reduce and mitigate coal dust throughout the coal handling system. The study emphasized the importance of having adequate wash down capability by installing and utilizing fixed pipe wash down systems in existing coal reclaim and conveyor tunnels, crusher houses, tripper bays and in the rail unloading hopper facilities. Recommendations were made on how to safely and reliably handle SPRB coal: keep areas clean, eliminate ignition sources and detect spontaneous combustion with accumulated SPRB coal dust. These safety steps are designed to protect people, equipment, and enclosures from explosions due to the dangerous spontaneous combustion tendencies of SPRB coal.

Required modifications to the rail delivery system outlined in the study indicate that the current unloading configuration is [redacted]. SPRB coal requirements at this level require the plant to receive approximately [redacted]

[redacted][5]

[5] PacifiCorp also engaged RungePincockMinarco to evaluate the impact from converting to SPRB coal on the Jim Bridger plant's stockpile level and configuration. This study was used to verify the findings of the Burns & McDonnell study.

[redacted].

Table 6 below shows a summary outline of BMcD’s total estimated costs, [redacted], associated with the different components referenced in their report.

TABLE 6

Jim Bridger Plant - Burns & McDonnell Estimated Capital Costs			
		[redacted]	[redacted]
Coal Handling	$	[redacted]	
Coal Handling Additional	$		
Existing Conveyor Scraper Tower with Wind Fence	$		
New Loop	$		
Power Island Modifications (Unit 1-4)	$		
Power Island Modifications (Unit 1-3 Only)	$		
Pulverizer Steam Inerting (Units 1-4)	$		
Electrical	$		
T&D	$		
Air Permit	$		
TOTAL	**$**		
Investment Total w/ Land/ROW Costs	**$**		
PacifiCorp Share (Includes AFUDC, Loadings)	**$**		

4 FUEL SUPPLY MIX OF PHASE 2 FUELING OPTIONS

The fueling options evaluated during Phase 2 are referenced as 2018 Fuel Plan Options D, E and F, including several variations on those primary options as described below. Please refer to Confidential Appendix B for detailed fueling mix and pricing information for each fueling option considered. The following summaries of the fuel supply mix, including average volumes for the near-term and long-term, for each fueling option evaluated are provided below:

4.1 OPTION D

Option D

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted][6]
      - PacifiCorp deliveries – [redacted]

[6] [redacted]

4.2 Option D ([redacted])

Option D ([redacted]) is a slight variation on Option D and contemplates [redacted]. Option D ([redacted]) assumes that in [redacted]. Option D ([redacted]) also assumes that the required capital investment is made to allow for the safe delivery and handling of a large volume of SPRB coal at that time.

Option D ([redacted])

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - Assumes plant capital (w/AFUDC and escalation) of [redacted]
        - [redacted]

4.3 OPTION E

Option E contemplates the closure of the Bridger mine in [redacted], as soon as practicable, and assumes [redacted] of the coal burned thereafter comes from the SPRB. This option assumes a required plant capital investment to safely and reliably deliver and consume large volumes of SPRB coal, approximately [redacted] million tons per year from [redacted]. The estimated investment is [redacted] million with AFUDC and escalation ([redacted] million PacifiCorp share) and includes a rail loop to comply with the railroad standard of unloading a unit train within six hours.

Option E

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - Underground mining operations [redacted]
    - Surface mining operations [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - Assumes plant capital (w/AFUDC and escalation) of [redacted]
        - [redacted]

4.4 OPTION F ([redacted])

Option F ([redacted]) considers the closure of the Bridger surface mining operations in [redacted] and the avoidance of [redacted] million ([redacted] million PacifiCorp share) in development costs required to permit and mine Deadman Wash, further refining Option D.

Option F

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]
- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - For 2018-2037 time period
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - [redacted]
        - [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]

4.5 OPTION F [redacted])

Option F ([redacted]) is a variation of Option F ([redacted]). The primary difference is that this scenario is based on a Bridger mine plan delivering [redacted] million tons per year in the near-term and assumes Black Butte mine Proposal D, the [redacted] million tons per year proposal, is chosen in the near-term as well.

Option F ([redacted])

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - For 2018-2037 time period
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
  - SPRB
    - SPRB deliveries [redacted]
      - [redacted]
        - [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]

4.6 OPTION F ([redacted])

Option F ([redacted]) is a slight variation on Option F and contemplates no longer purchasing Black Butte mine coal after the near-term Coal Supply Agreement ends. Option F ([redacted]) assumes that [redacted] coal replaces Black Butte mine coal in [redacted]. Option F ([redacted]) also assumes that the required capital investment is made to allow for the safe delivery and handling of a [redacted].

Option F ([redacted])

- Near-term deliveries (2018-2021)
    - Bridger mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - Total deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
        - [redacted]

- Long-Term deliveries (2022-2037)
    - Bridger mine
        - [redacted]
        - Total Deliveries – [redacted]
        - PacifiCorp deliveries – [redacted]
    - Black Butte mine
        - [redacted]
    - SPRB
        - SPRB deliveries from [redacted]
            - Total deliveries – [redacted]
            - PacifiCorp deliveries – [redacted]
            - [redacted]
                - Peak deliveries will occur from 2029 through 2032 – [redacted]

5 PVRR ANALYSIS & RESULTS

Table 7 below shows the results of a PVRR analysis for each fueling option in the 2018 Fuel Plan. The PVRR analysis represents a present value revenue requirement analysis of the total delivered fuel costs and the estimated capital requirements for both the Jim Bridger plant and the Bridger mine, discounted by PacifiCorp's weighted average cost of capital. A total dollar PVRR variance or differential has also been calculated for every fueling option comparing the total PVRR dollar for each fueling option against Option [redacted]. Also included in Table 7 is a financial ranking from 1 to 6 for each of the six fueling options. The Table shows Option [redacted] is ranked [redacted], and Option [redacted] is ranked number [redacted]. The other fueling options fall between these two options. Additional discussion on risk assessment for each fueling option is shown below.

TABLE 7

Jim Bridger Plant Fueling Evaluation (2018-2037) - PacifiCorp Share								
PVRR Summary PAC Portion	PVRR (000's)	PVRR Differential (from lowest $)	Financial Ranking (low to high)	Percent Change (%)	Risk Ranking (low to high)	Project Ranking (Weighted - Financial 60%, Risk, 40%)	Plant Capital (w/AFUDC and escalation, 000's)	Bridger Coal Capital (2018-LOM, escalated, 000's)
[redacted]								

Table 8 presents a risk table for each option and outlines the specific categories that have been considered in the risk evaluation analysis.

TABLE 8

Jim Bridger Plant Fueling Risk Evaluation (2018-2037)							
Options	Risk Ranking (low to high)	Composite Project Risk Score	Incremental Capital	Coal Market	Power Market Volatility	Jim Bridger Plant Environmental Compliance	Deadman Wash Lease Permitting
[redacted]							

The different categories making up the defined risk profile include (1) incremental capital – the risks associated with the total costs of incremental capital expenditures related to each fueling option, (2) coal market – risks associated with adequate coal supplies, as well as coal & transportation price escalation, (3) power market volatility – risks associated with power market price volatility related to changing natural gas prices, the impacts of renewable energy sources impacting GRID dispatch, all which could result in reduced coal consumption, (4) environmental compliance – risks associated with new environmental regulations that could reduce coal generation at the Jim Bridger plant, and (5) Deadman Wash permitting – risks associated with being able to permit the Deadman Wash coal reserve tract in the estimated number of years that would allow the Bridger mine to access the Deadman Wash coal reserve tract and achieve the projected mine cost savings.

For each fueling option under each risk category, a number 1, 2, or 3 has been assigned. Number 1 is designated as "most favorable and low risk." number 2 is "less favorable and moderate risk," and number 3 is "least favorable and high risk." The summation of the assigned risk number for each category for each fueling option, results in an overall "composite project risk" score.

As shown in Table 8, the fueling option with the highest composite risk score is fueling Option [redacted] with a score of [redacted]. Option [redacted] requires incremental capital associated with both the Deadman Wash coal tract as well as new plant capital to support future SPRB coal deliveries. As such, there is added risk for Option [redacted] associated with the capital projects meeting projected cost estimates. Furthermore, there is additional risk associated with the permitting of the Deadman Wash coal reserves in sufficient time which allows for the projected coal production and deliveries from the Bridger mine to be realized. An additional sensitivity was run that determined that for each year of delay in the Deadman Wash permit, the total PVRR amount calculated for Option [redacted] increases by approximately [redacted]. This further closes the PVRR differential gap between Option [redacted] and the other fueling options. The fuel option with the lowest composite risk score, or most favorable score, is Option [redacted]. Under this option there is no incremental capital required and there is very low risk associated with the coal supplies. The other five fueling options have a composite risk score that falls between Option [redacted] and Option [redacted].

All six fuel options are ranked on ascending order from 1 to 6 based upon their composite risk score. Option [redacted] has the most favorable risk option score of [redacted], while Option [redacted] has the worst or highest ranking of [redacted].

From the financial and risk rankings, an overall project ranking has been determined for each fueling option. The overall project weighting is the result of assigning a weighting of [redacted] to the financial ranking and [redacted] to the risk ranking.

As seen in Table 7, in spite of Option [redacted] having the financial ranking of [redacted], it has a risk ranking of [redacted]. This results in an overall project ranking of [redacted]. Option [redacted], has a financial ranking of [redacted], but has the lowest risk ranking of [redacted]. With the weighting between financial and risk rankings, Option [redacted] has the best overall project ranking and is the preferred fueling option. The fueling option with the worst overall project ranking of [redacted] is Option [redacted]. The remaining fueling options are ranked in between Option [redacted] and Option [redacted].[7]

[7] Additional sensitivity analysis was performed on two options. (1) Plant capital was reduced in Option [redacted] for the assumed removal of the rail loop. This change resulted in a reduction to the PVRR differential for Option [redacted] as the savings in capital were offset by increased transportation costs resulting from increased coal unloading times. (2) Option [redacted] was evaluated assuming that approximately [redacted] was purchased in years requiring high volumes of [redacted], deliveries in excess of [redacted]. The [redacted] purchases of roughly [redacted], reduced Black Butte mine volumes in those years. Due to the higher delivered fuel cost of the [redacted], this change resulted in an increase to the PVRR differential for Option [redacted].

6 CONCLUSION

Over the past two years, PacifiCorp has developed a long-term fueling strategy for the Jim Bridger plant to align with the Company's IRP and respond to changing fuel requirements due to market conditions. Mine plans have been run, evaluated and reviewed for the Bridger mine. The various mine options have provided information and direction in determining the optimal total tonnage mix at the Bridger mine for both the underground mine and the surface mine. Different mine closure dates for both the underground mine and the surface mining operations have been considered and evaluated.

Over many months, numerous discussions and negotiations occurred with Lighthouse and the Union Pacific Railroad to develop new near-term coal and transportation agreements. Through these negotiations, new contract rates from different coal regions were obtained. Additionally, long-term indicative rail rates from mines located in the SPRB were provided by the Union Pacific Railroad for coal deliveries to the plant.

In addition to the estimated future coal and transportation rates provided, PacifiCorp also contracted for two consulting studies which provided important information in the PVRR analysis. These two studies were requested to better understand the overall fueling impacts, capital requirements and estimated costs related to a full or partial SPRB fuel switch at the plant. BMcD, a reputable engineering consulting company, completed a comprehensive fuel impact study in June 2017. The study outlined the relevant issues and total estimated costs that would be required to undertake a SPRB coal conversion at the plant.

After considering all of the factors influencing this long-term fueling strategy, six different fueling options were developed and evaluated. Based upon the results of the detailed PVRR analysis, which was further enhanced by utilizing a risk profile, Option [redacted] is the current least-cost, least-risk option and the strategy PacifiCorp is currently pursuing which includes the following:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

While the current analyses shows Option [redacted] as the least-cost, least-risk option, Option [redacted] is the lowest cost option and will continue to be analyzed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking into consideration both cost and risk of the different options and will change the long-term fuel plan as necessary to provide the least-cost, least-risk long-term fuel supply for the Jim Bridger plant. Furthermore, both Options [redacted] and Option [redacted], allow PacifiCorp to [redacted]

This strategy allows PacifiCorp and the plant to maintain significant fuel supply flexibility related to future decisions impacting the plant's generation and potential unit closures. [redacted]

REDACTED

Confidential Appendix A

Jim Bridger Plant - Generation Summary
Generation Forecast
All Participant Shares - In Millions

Plan Comparison

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Dec-'15 Long Term Fuel Plan																					
MMBtu's Required	[redacted]																				
Forecasted Generation (MWh)																					
2018 Fuel Plan																					
MMBtu's Required																					
Forecasted Generation (MWh)																					
Variance																					
MMBtu's Required																					
Forecasted Generation (MWh)																					
Percent Change (%)																					

CONFIDENTIAL APPENDIX B-OPTION D

Jim Bridger Plant - Option D
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX B-OPTION D ([redacted])

Jim Bridger Plant - Option D ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
Tons	[redacted]																				
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX B-OPTION E

Jim Bridger Plant - Option E
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

CONFIDENTIAL APPENDIX B-OPTION F [redacted]

Jim Bridger Plant - Option F ([redacted]
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
Tons	[redacted]																				
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
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Total Coal Received																					
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MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

CONFIDENTIAL APPENDIX B-OPTION F ([redacted])

Jim Bridger Plant - Option F ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
Tons	[redacted]																				
MMBTUs																					
Dollars																					
$/Ton																					
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Black Butte																					
Tons																					
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Total Coal Received																					
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Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX B-OPTION F ([redacted])

Jim Bridger Plant - Option F ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
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Black Butte																					
Tons																					
MMBTU																					
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Regional Coal																					
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Total Coal Received																					
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MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX C-RISK RANKING

Jim Bridger Plant Fueling Risk Evaluation (2018-2037)							
Options	Risk Ranking (low to high)	Composite Project Risk Score	Incremental Capital	Coal Market	Power Market Volatility	Jim Bridger Plant Environmental Compliance	Deadman Wash Lease Permitting
[redacted]							

Docket No. UE 339
Exhibit PAC/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

March 2018

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.

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

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

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

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present PacifiCorp's proposed rate spread, rates, and revised tariff pages for the 2019 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and the TAM adjustments for other revenues identified by Mr. Michael G. Wilding. 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. PacifiCorp collects NPC through Schedule 201, Net Power Costs, Cost-Based Supply

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

Q. What is the test period for this TAM?

A. In accordance with the TAM Guidelines adopted in Order No. 09-274,[1] the test period for the TAM is the year during which the Schedule 201 rates will be effective, which is the 12 months ending December 31, 2019.

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

A. PacifiCorp allocated forecast NPC to the customer classes based on the present spread of NPC revenue. This is consistent with the TAM Guidelines and the stipulated generation allocation factors in the company's last general rate case, approved by the Public Utility Commission of Oregon in Order No. 13-474,[2] updated for the change in load.

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

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

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

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

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

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

A. PacifiCorp'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. Present rates for Schedule 205 were established in the company's 2018 TAM, docket UE 323.[3] Historically, PacifiCorp has proposed changes to the present Schedule 205 rates reflecting the additional adjustment related to other revenues. However, the $0.03 million change in the adjustment indicated in this case as presented in Mr. Wilding's testimony is too small to create a billable rate adjustment.[4] Therefore the company proposes no change to the rates in Schedule 205 at this time. Should the amount related to other revenues change significantly in subsequent TAM updates, the company will propose to update Schedule 205 accordingly, consistent with past practice.

Q. Please describe Exhibit PAC/302.

A. Exhibit PAC/302 contains the proposed revised Schedule 201.

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[3] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 (Nov. 1, 2017).
[4] PacifiCorp's energy rates bill to the thousandth of one cent.

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

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

COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

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

A. The overall proposed effect is a rate increase of 1.3 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/303 shows the estimated effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

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

A. Yes. Exhibit PAC/303, beginning on page two, 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 $1.12.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 339
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

March 2018

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2019

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	3,993,128,779	2.624 ¢	$104,779,699	28.7899%	$109,630,081	2.745 ¢	$109,611,385
Second Block kWh (> 1,000)	1,408,634,806	3.585 ¢	$50,499,558	13.8755%	$52,837,245	3.751 ¢	$52,837,892
	5,401,763,585		$155,279,257		$162,467,327		$162,449,277
						Change	$7,170,020
Employee Discount							
First Block kWh (0-1,000)	11,541,963	2.624 ¢	$302,861			2.745 ¢	$316,827
Second Block kWh (> 1,000)	5,433,577	3.585 ¢	$194,794			3.751 ¢	$203,813
	16,975,540		$497,655				$520,640
Discount			-$124,414				-$130,160
						Change	-$5,746
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	898,451,739	2.906 ¢	$26,109,008	7.1739%	$27,317,626	3.042 ¢	$27,330,902
All additional kWh, per kWh	239,695,901	2.155 ¢	$5,165,447	1.4193%	$5,404,562	2.255 ¢	$5,405,143
	1,138,147,640		$31,274,455		$32,722,188		$32,736,045
						Change	$1,461,590
Primary Voltage							
1st 3,000 kWh, per kWh	747,804	2.815 ¢	$21,051	0.0058%	$22,025	2.945 ¢	$22,023
All additional kWh, per kWh	326,611	2.088 ¢	$6,820	0.0019%	$7,136	2.185 ¢	$7,136
	1,074,415		$27,871		$29,161		$29,159
						Change	$1,288
Schedule 28, General Service 31-200kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	1,387,609,618	2.842 ¢	$39,435,865	10.8356%	$41,261,400	2.974 ¢	$41,267,510
All additional kWh, per kWh	566,284,646	2.763 ¢	$15,646,445	4.2991%	$16,370,738	2.891 ¢	$16,371,289
	1,953,894,264		$55,082,310		$57,632,139		$57,638,799
						Change	$2,556,489
Primary Voltage							
1st 20,000 kWh, per kWh	9,549,483	2.736 ¢	$261,274	0.0718%	$273,369	2.863 ¢	$273,402
All additional kWh, per kWh	8,592,865	2.663 ¢	$228,828	0.0629%	$239,421	2.786 ¢	$239,397
	18,142,348		$490,102		$512,789		$512,799
						Change	$22,697
Schedule 30, General Service 201-999kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	178,605,886	3.038 ¢	$5,426,047	1.4909%	$5,677,225	3.179 ¢	$5,677,881
All additional kWh, per kWh	1,058,983,801	2.634 ¢	$27,893,633	7.6642%	$29,184,864	2.756 ¢	$29,185,594
	1,237,589,687		$33,319,680		$34,862,089		$34,863,475
						Change	$1,543,795
Primary Voltage							
1st 20,000 kWh, per kWh	12,169,962	3.005 ¢	$365,707	0.1005%	$382,636	3.144 ¢	$382,624
All additional kWh, per kWh	78,811,664	2.597 ¢	$2,046,739	0.5624%	$2,141,485	2.717 ¢	$2,141,313
	90,981,626		$2,412,446		$2,524,121		$2,523,937
						Change	$111,491
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
Winter, 1st 100 kWh/kW, per kWh	2,908,467	4.058 ¢	$118,026	0.0324%	$123,490	4.246 ¢	$123,494
Winter, All additional kWh, per kWh	2,420,718	2.765 ¢	$66,933	0.0184%	$70,031	2.893 ¢	$70,031
Summer, All kWh, per kWh	216,836,647	2.765 ¢	$5,995,533	1.6474%	$6,273,074	2.893 ¢	$6,273,084
	222,165,832		$6,180,492		$6,466,595		$6,466,609
						Change	$286,117
Primary Voltage							
Winter, 1st 100 kWh/kW, per kWh	10,850	3.922 ¢	$426	0.0001%	$446	4.108 ¢	$446
Winter, All additional kWh, per kWh	62,057	2.678 ¢	$1,662	0.0005%	$1,739	2.802 ¢	$1,739
Summer, All kWh, per kWh	385,713	2.678 ¢	$10,329	0.0028%	$10,807	2.802 ¢	$10,808
	458,620		$12,417		$12,992		$12,993
						Change	$576
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	26,421,661	2.485 ¢	$656,578			2.599 ¢	$686,699
Off-Peak, per off-peak kWh	8,741,534	2.435 ¢	$212,856			2.549 ¢	$222,822
	35,163,195		$869,434		$909,521		$909,521
						Change	$40,087
Transmission Voltage							
On-Peak, per on-peak kWh	5,452,075	2.334 ¢	$127,251			2.441 ¢	$133,085
Off-Peak, per off-peak kWh	6,639,997	2.284 ¢	$151,658			2.391 ¢	$158,762
	12,092,072		$278,909		$291,847		$291,847
						Change	$12,938

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2019

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over							
Secondary Voltage							
On-Peak, per on-peak kWh	341,147,887	2.679 ¢	$9,139,352	2.5112%	$9,562,424	2.802 ¢	$9,558,964
Off-Peak, per off-peak kWh	187,883,573	2.629 ¢	$4,939,459	1.3572%	$5,168,113	2.752 ¢	$5,170,556
	529,031,460		$14,078,811		$14,730,537		$14,729,520
						Change	$650,709
Primary Voltage							
On-Peak, per on-peak kWh	1,006,730,271	2.485 ¢	$25,017,247	6.8739%	$26,175,326	2.599 ¢	$26,164,920
Off-Peak, per off-peak kWh	633,990,182	2.435 ¢	$15,437,661	4.2417%	$16,152,290	2.549 ¢	$16,160,410
	1,640,720,453		$40,454,908		$42,327,616		$42,325,330
						Change	$1,870,422
Transmission Voltage							
On-Peak, per on-peak kWh	597,005,583	2.334 ¢	$13,934,110	3.8286%	$14,579,137	2.441 ¢	$14,572,906
Off-Peak, per off-peak kWh	454,280,029	2.284 ¢	$10,375,756	2.8509%	$10,856,063	2.391 ¢	$10,861,835
	1,051,285,612		$24,309,866		$25,435,200		$25,434,741
						Change	$1,124,875
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	9,057,816	2.187 ¢	$197,957	0.0544%	$207,121	2.287 ¢	$207,210
	9,057,816		$197,957		$207,121		$207,210
						Change	$9,253
Schedule 50, Mercury Vapor Street Lighting Service							
Secondary Voltage							
All kWh, per kWh	7,713,067	1.804 ¢	$139,033	0.0382%	$145,469	1.886 ¢	$145,167
	7,713,067		$139,033		$145,469		$145,167
						Change	$6,134
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	19,939,528	2.843 ¢	$566,838	0.1557%	$593,078	2.974 ¢	$593,240
	19,939,528		$566,838		$593,078		$593,240
						Change	$26,402
Schedule 52, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	404,011	2.178 ¢	$8,799	0.0024%	$9,207	2.279 ¢	$9,207
	404,011		$8,799		$9,207		$9,207
						Change	$408
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	9,677,685	0.928 ¢	$89,809	0.0247%	$93,966	0.971 ¢	$93,970
	9,677,685		$89,809		$93,966		$93,970
						Change	$4,161
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,344,749	1.602 ¢	$21,543	0.0059%	$22,540	1.676 ¢	$22,538
	1,344,749		$21,543		$22,540		$22,538
						Change	$995
Total before Employee Discount			**$365,094,937**	100.0000%	$381,995,502		**$381,995,385**
Employee Discount			-$124,414		-$130,160		-$130,160
TOTAL	**13,380,647,665**		**$364,970,523**		$381,865,342		**$381,865,225**
						Change	**$16,894,702**
Schedule 47 Unscheduled kWh	2,604,109						
Total Forecast kWH	13,383,251,774						

Docket No. UE 339
Exhibit PAC/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedules

March 2018

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 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

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

Monthly Billing

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

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	2.745¢			(I)
		> 1000 kWh	3.751¢			
5	Per kWh	0-1000 kWh	2.745¢			
		> 1000 kWh	3.751¢			(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	3.042¢	2.945¢		(I)
	All additional kWh, per kWh	2.255¢	2.185¢		
28	First 20,000 kWh, per kWh	2.974¢	2.863¢		
	All additional kWh, per kWh	2.891¢	2.786¢		
30	First 20,000 kWh, per kWh	3.179¢	3.144¢		
	All additional kWh, per kWh	2.756¢	2.717¢		
41	Winter, first 100 kWh/kW, per kWh	4.246¢	4.108¢		
	Winter, all additional kWh, per kWh	2.893¢	2.802¢		
	Summer, all kWh, per kWh	2.893¢	2.802¢		(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.		Delivery Voltage Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	2.802¢	2.599¢	2.441¢	(I)
	Per kWh, Off-Peak	2.752¢	2.549¢	2.391¢	(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. At such time as updated DST programming is available and has been applied to a Consumer meter, the time periods shown above will apply on all days for that Consumer. Consumers will be notified of their change to updated DST programming in a timely manner.

52	For dusk to dawn operation, per kWh	2.279¢	(I)
	For dusk to midnight operation, per kWh	2.279¢	
54	Per kWh	1.676¢	(I)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$ 1.74	(I)
Mercury Vapor	21,000	172	$ 3.93	
Mercury Vapor	55,000	412	$ 9.42	
High Pressure Sodium	5,800	31	$ 0.71	
High Pressure Sodium	22,000	85	$ 1.94	
High Pressure Sodium	50,000	176	$ 4.03	(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	$1.43	$3.24	$7.77	(I)
Vertical, per lamp	$1.43	$3.24		(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	$1.43			(I)
On 26-foot poles, vertical, per lamp	$1.43			
On 30-foot poles, horizontal, per lamp		$3.24		
On 30-foot poles, vertical, per lamp		$3.24		
On 33-foot poles, horizontal, per lamp			$7.77	(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	$1.43			(I)
On 26-foot poles, vertical, per lamp	$1.43			
On 30-foot poles, horizontal, per lamp		$3.24		
On 30-foot poles, vertical, per lamp		$3.24		
On 33-foot poles, horizontal, per lamp			$7.77	(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)		$0.80	
LED	13,000	250 (comp)		$1.52	
LED	16,800	400 (comp)		$2.05	
High Pressure Sodium	5,800	70	31	$0.92	
High Pressure Sodium	9,500	100	44	$1.31	
High Pressure Sodium	16,000	150	64	$1.90	
High Pressure Sodium	22,000	200	85	$2.53	
High Pressure Sodium	27,500	250	115	$3.42	
High Pressure Sodium	50,000	400	176	$5.23	
Metal Halide	12,000	175	68	$2.02	
Metal Halide	19,500	250	94	$2.80	(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	$0.62	
High Pressure Sodium	22,000	200	85	$0.83	
High Pressure Sodium	27,500	250	115	$1.12	
High Pressure Sodium	50,000	400	176	$1.71	
Metal Halide	9,000	100	39	$0.38	
Metal Halide	12,000	175	68	$0.66	
Metal Halide	19,500	250	94	$0.91	
Metal Halide	32,000	400	149	$1.45	
Metal Halide	107,800	1,000	354	$3.44	

Non-Listed Luminaire, per kWh 0.971¢ (I)

(continued)

Docket No. UE 339
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

March 2018

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, 2019

					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	506,345	5,401,764	$623,235	$5,942	$629,177	$630,405	$5,942	$636,347	$7,170	1.2%	$7,170	1.1%	1
2	**Total Residential**		506,345	5,401,764	$623,235	$5,942	$629,177	$630,405	$5,942	$636,347	$7,170	1.2%	$7,170	1.1%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	$126,505	$5,296	$131,801	$127,967	$5,296	$133,263	$1,462	1.2%	$1,462	1.1%	3
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	$181,441	$3,372	$184,813	$184,021	$3,372	$187,393	$2,580	1.4%	$2,580	1.4%	4
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	$108,451	$1,276	$109,727	$110,107	$1,276	$111,383	$1,656	1.5%	$1,656	1.5%	5
6	Large General Service >= 1,000 kW	48	195	3,221,037	$226,897	($9,525)	$217,372	$230,542	($9,525)	$221,017	$3,645	1.6%	$3,645	1.7%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859	$5,617	($152)	$5,465	$5,670	($152)	$5,518	$53	1.6%	$53	1.7%	7
8	Agricultural Pumping Service	41	7,982	222,624	$25,979	($1,219)	$24,760	$26,266	($1,219)	$25,047	$287	1.1%	$287	1.2%	8
9	**Total Commercial & Industrial**		100,164	7,933,350	$674,890	($952)	$673,938	$684,573	($952)	$683,621	$9,683	1.4%	$9,683	1.4%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,305	9,058	$1,167	$216	$1,383	$1,176	$216	$1,392	$9	0.8%	$9	0.7%	10
11	Street Lighting Service	50	225	7,713	$861	$169	$1,030	$867	$169	$1,036	$6	0.7%	$6	0.6%	11
12	Street Lighting Service HPS	51	815	19,940	$3,514	$723	$4,237	$3,541	$723	$4,264	$27	0.8%	$27	0.6%	12
13	Street Lighting Service	52	35	404	$53	$9	$62	$53	$9	$62	$0	0.0%	$0	0.0%	13
14	Street Lighting Service	53	273	9,678	$611	$121	$732	$615	$121	$736	$4	0.7%	$4	0.6%	14
15	Recreational Field Lighting	54	104	1,345	$112	$21	$133	$113	$21	$134	$1	0.9%	$1	0.8%	15
16	**Total Public Street Lighting**		7,757	48,138	$6,318	$1,259	$7,577	$6,365	$1,259	$7,624	$47	0.7%	$47	0.6%	16
17	**Total Sales before Emp. Disc. & AGA**		614,266	13,383,252	$1,304,443	$6,249	$1,310,692	$1,321,343	$6,249	$1,327,592	$16,900	1.3%	$16,900	1.3%	17
18	Employee Discount				($484)	($4)	($488)	($490)	($4)	($494)	($6)		($6)		18
19	**Total Sales with Emp. Disc**		614,266	13,383,252	$1,303,959	$6,245	$1,310,204	$1,320,853	$6,245	$1,327,098	$16,894	1.3%	$16,894	1.3%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		614,266	13,383,252	$1,306,398	$6,245	$1,312,643	$1,323,292	$6,245	$1,329,537	$16,894	1.3%	$16,894	1.3%	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	$20.28	$20.40	$0.12	0.59%
200	$30.05	$30.31	$0.26	0.87%
300	$39.84	$40.21	$0.37	0.93%
400	$49.62	$50.12	$0.50	1.01%
500	$59.42	$60.04	$0.62	1.04%
600	$69.21	$69.97	$0.76	1.10%
700	$78.99	$79.87	$0.88	1.11%
800	$88.79	$89.78	$0.99	1.11%
900	**$98.56**	**$99.68**	**$1.12**	**1.14%**
950	$103.47	$104.65	$1.18	1.14%
1,000	$108.36	$109.61	$1.25	1.15%
1,100	$121.31	$122.73	$1.42	1.17%
1,200	$134.25	$135.84	$1.59	1.18%
1,300	$147.21	$148.97	$1.76	1.20%
1,400	$160.15	$162.08	$1.93	1.21%
1,500	$173.10	$175.20	$2.10	1.21%
1,600	$186.05	$188.33	$2.28	1.23%
2,000	$237.84	$240.80	$2.96	1.24%
3,000	$367.33	$372.00	$4.67	1.27%
4,000	$496.81	$503.19	$6.38	1.28%
5,000	$626.30	$634.39	$8.09	1.29%

* 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 Load Size	kWh	Monthly Billing* Present Price Single Phase	Present Price Three Phase	Proposed Price Single Phase	Proposed Price Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
5	500	$72	$81	$73	$82	0.97%	0.86%
	750	$100	$108	$101	$110	1.05%	0.97%
	1,000	$127	$136	$128	$137	1.10%	1.03%
	1,500	$181	$190	$184	$192	1.16%	1.10%
10	1,000	$127	$136	$128	$137	1.10%	1.03%
	2,000	$236	$245	$239	$248	1.19%	1.14%
	3,000	$345	$354	$349	$358	1.22%	1.19%
	4,000	$437	$446	$443	$451	1.20%	1.17%
20	4,000	$464	$473	$470	$478	1.13%	1.11%
	6,000	$649	$658	$656	$665	1.12%	1.11%
	8,000	$834	$842	$843	$852	1.12%	1.11%
	10,000	$1,018	$1,027	$1,030	$1,039	1.12%	1.11%
30	9,000	$980	$989	$990	$999	1.06%	1.05%
	12,000	$1,257	$1,266	$1,270	$1,279	1.07%	1.06%
	15,000	$1,534	$1,543	$1,550	$1,559	1.08%	1.07%
	18,000	$1,811	$1,820	$1,831	$1,839	1.09%	1.08%

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

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

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$80	$72	$80	0.94%	0.84%
	750	$98	$106	$99	$107	1.03%	0.94%
	1,000	$124	$133	$125	$134	1.08%	1.01%
	1,500	$177	$186	$179	$188	1.13%	1.08%
10	1,000	$124	$133	$125	$134	1.08%	1.01%
	2,000	$230	$239	$233	$242	1.16%	1.12%
	3,000	$336	$345	$340	$349	1.19%	1.16%
	4,000	$426	$435	$431	$440	1.18%	1.15%
20	4,000	$453	$462	$458	$467	1.11%	1.09%
	6,000	$633	$641	$640	$648	1.11%	1.09%
	8,000	$813	$821	$822	$830	1.11%	1.10%
	10,000	$992	$1,001	$1,003	$1,012	1.11%	1.10%
30	9,000	$955	$964	$965	$974	1.05%	1.04%
	12,000	$1,225	$1,234	$1,238	$1,247	1.06%	1.05%
	15,000	$1,495	$1,504	$1,511	$1,520	1.07%	1.06%
	18,000	$1,765	$1,774	$1,784	$1,793	1.08%	1.07%

* 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	$353	$357	1.15%
	4,500	$468	$474	1.31%
	7,500	$696	$707	1.46%
31	6,200	$710	$719	1.19%
	9,300	$947	$959	1.34%
	15,500	$1,420	$1,441	1.48%
40	8,000	$911	$922	1.19%
	12,000	$1,216	$1,233	1.34%
	20,000	$1,826	$1,853	1.49%
60	12,000	$1,359	$1,375	1.20%
	18,000	$1,816	$1,841	1.35%
	30,000	$2,714	$2,754	1.49%
80	16,000	$1,800	$1,822	1.21%
	24,000	$2,403	$2,435	1.35%
	40,000	$3,595	$3,649	1.49%
100	20,000	$2,241	$2,268	1.21%
	30,000	$2,986	$3,027	1.35%
	50,000	$4,477	$4,543	1.49%
200	40,000	$4,389	$4,442	1.22%
	60,000	$5,879	$5,959	1.36%
	100,000	$8,860	$8,993	1.50%

* 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	$455	$461	1.30%
	6,000	$559	$567	1.40%
	7,500	$664	$674	1.48%
31	9,300	$913	$926	1.33%
	12,400	$1,129	$1,146	1.44%
	15,500	$1,345	$1,366	1.51%
40	12,000	$1,172	$1,187	1.34%
	16,000	$1,450	$1,471	1.44%
	20,000	$1,729	$1,755	1.51%
60	18,000	$1,747	$1,770	1.35%
	24,000	$2,158	$2,190	1.45%
	30,000	$2,566	$2,605	1.51%
80	24,000	$2,309	$2,340	1.35%
	32,000	$2,853	$2,894	1.45%
	40,000	$3,397	$3,448	1.52%
100	30,000	$2,867	$2,906	1.35%
	40,000	$3,547	$3,599	1.45%
	50,000	$4,227	$4,292	1.52%
200	60,000	$5,623	$5,700	1.37%
	80,000	$6,984	$7,086	1.46%
	100,000	$8,344	$8,472	1.53%

* 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 Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	20,000	$2,670	$2,699	1.09%
	30,000	$3,272	$3,314	1.27%
	50,000	$4,477	$4,544	1.49%
200	40,000	$4,695	$4,749	1.15%
	60,000	$5,900	$5,979	1.34%
	100,000	$8,309	$8,439	1.56%
300	60,000	$6,890	$6,970	1.15%
	90,000	$8,698	$8,815	1.35%
	150,000	$12,312	$12,504	1.56%
400	80,000	$8,967	$9,072	1.16%
	120,000	$11,377	$11,532	1.36%
	200,000	$16,196	$16,451	1.58%
500	100,000	$11,075	$11,205	1.17%
	150,000	$14,087	$14,279	1.37%
	250,000	$20,111	$20,429	1.58%
600	120,000	$13,183	$13,338	1.17%
	180,000	$16,797	$17,027	1.37%
	300,000	$24,026	$24,407	1.59%
800	160,000	$17,398	$17,603	1.18%
	240,000	$22,218	$22,523	1.38%
	400,000	$31,856	$32,363	1.59%
1000	200,000	$21,614	$21,869	1.18%
	300,000	$27,638	$28,019	1.38%
	500,000	$39,686	$40,318	1.59%

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

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,209	$3,250	1.28%
	40,000	$3,800	$3,853	1.40%
	50,000	$4,391	$4,457	1.50%
200	60,000	$5,789	$5,867	1.35%
	80,000	$6,971	$7,074	1.47%
	100,000	$8,153	$8,281	1.56%
300	90,000	$8,529	$8,644	1.35%
	120,000	$10,302	$10,454	1.48%
	150,000	$12,075	$12,264	1.57%
400	120,000	$11,174	$11,326	1.36%
	160,000	$13,538	$13,739	1.49%
	200,000	$15,902	$16,153	1.58%
500	150,000	$13,831	$14,021	1.37%
	200,000	$16,786	$17,037	1.50%
	250,000	$19,741	$20,054	1.59%
600	180,000	$16,489	$16,715	1.37%
	240,000	$20,034	$20,335	1.50%
	300,000	$23,580	$23,955	1.59%
800	240,000	$21,803	$22,104	1.38%
	320,000	$26,531	$26,931	1.51%
	400,000	$31,259	$31,757	1.59%
1000	300,000	$27,118	$27,493	1.38%
	400,000	$33,028	$33,526	1.51%
	500,000	$38,937	$39,559	1.60%

* 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	$194	$222	$155	$196	$225	$155	1.36%	1.46%	0.00%
	3,000	$290	$319	$155	$294	$324	$155	1.36%	1.44%	0.00%
	5,000	$484	$513	$155	$491	$520	$155	1.36%	1.41%	0.00%
Three Phase										
20	4,000	$387	$444	$309	$393	$451	$309	1.36%	1.46%	0.00%
	6,000	$581	$638	$309	$589	$647	$309	1.36%	1.43%	0.00%
	10,000	$968	$1,025	$309	$981	$1,040	$309	1.36%	1.41%	0.00%
100	20,000	$1,937	$2,222	$1,349	$1,963	$2,255	$1,349	1.36%	1.46%	0.00%
	30,000	$2,905	$3,191	$1,349	$2,944	$3,236	$1,349	1.36%	1.43%	0.00%
	50,000	$4,841	$5,127	$1,349	$4,907	$5,199	$1,349	1.36%	1.41%	0.00%
300	60,000	$5,810	$6,667	$3,409	$5,889	$6,765	$3,409	1.36%	1.46%	0.00%
	90,000	$8,714	$9,572	$3,409	$8,833	$9,709	$3,409	1.36%	1.43%	0.00%
	150,000	$14,524	$15,382	$3,409	$14,722	$15,598	$3,409	1.36%	1.41%	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	$281	$309	$155	$285	$313	$155	1.37%	1.45%	0.00%
	4,000	$375	$403	$155	$380	$408	$155	1.36%	1.43%	0.00%
	5,000	$469	$496	$155	$475	$503	$155	1.36%	1.42%	0.00%
Three Phase										
20	6,000	$563	$618	$309	$570	$627	$309	1.36%	1.45%	0.00%
	8,000	$750	$805	$309	$760	$817	$309	1.36%	1.43%	0.00%
	10,000	$938	$993	$309	$950	$1,007	$309	1.36%	1.42%	0.00%
100	30,000	$2,813	$3,089	$1,339	$2,851	$3,134	$1,339	1.36%	1.45%	0.00%
	40,000	$3,750	$4,027	$1,339	$3,801	$4,084	$1,339	1.36%	1.43%	0.00%
	50,000	$4,688	$4,964	$1,339	$4,752	$5,035	$1,339	1.36%	1.42%	0.00%
300	90,000	$8,438	$9,268	$3,399	$8,553	$9,402	$3,399	1.36%	1.45%	0.00%
	120,000	$11,251	$12,080	$3,399	$11,404	$12,253	$3,399	1.36%	1.43%	0.00%
	150,000	$14,064	$14,893	$3,399	$14,255	$15,104	$3,399	1.36%	1.41%	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	$26,904	$27,284	1.41%
	500,000	$38,417	$39,051	1.65%
	650,000	$47,052	$47,875	1.75%
2,000	600,000	$53,376	$54,136	1.42%
	1,000,000	$74,152	$75,419	1.71%
	1,300,000	$90,596	$92,243	1.82%
6,000	1,800,000	$154,894	$157,175	1.47%
	3,000,000	$220,672	$224,473	1.72%
	3,900,000	$270,006	$274,947	1.83%
12,000	3,600,000	$308,464	$313,025	1.48%
	6,000,000	$440,020	$447,622	1.73%
	7,800,000	$538,687	$548,569	1.83%

Notes:

On-Peak kWh	64.49%
Off-Peak kWh	35.51%

* 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	$25,449	$25,802	1.38%
	500,000	$36,142	$36,729	1.62%
	650,000	$44,162	$44,925	1.73%
2,000	600,000	$50,425	$51,129	1.40%
	1,000,000	$69,561	$70,735	1.69%
	1,300,000	$84,775	$86,301	1.80%
6,000	1,800,000	$145,640	$147,754	1.45%
	3,000,000	$206,497	$210,020	1.71%
	3,900,000	$252,140	$256,720	1.82%
12,000	3,600,000	$289,926	$294,153	1.46%
	6,000,000	$411,640	$418,685	1.71%
	7,800,000	$502,926	$512,085	1.82%

Notes:

On-Peak kWh	61.36%
Off-Peak kWh	38.64%

* 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		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	500,000	$35,836	$36,388	1.54%
	650,000	$43,307	$44,023	1.65%
2,000	1,000,000	$68,537	$69,639	1.61%
	1,300,000	$82,653	$84,085	1.73%
6,000	3,000,000	$203,602	$206,908	1.62%
	3,900,000	$245,949	$250,247	1.75%
12,000	6,000,000	$405,056	$411,669	1.63%
	7,800,000	$489,749	$498,346	1.76%
50,000	25,000,000	$1,680,931	$1,708,484	1.64%
	32,500,000	$2,033,821	$2,069,639	1.76%

Notes:

On-Peak kWh	56.79%
Off-Peak kWh	43.21%

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