PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 1, 2019

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. 19-007/UE 356—PacifiCorp's 2020 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, 2020.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2020 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/303. 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

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

PacifiCorp will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—along with any needed changes to Schedule 293 New Large Load Direct Access Program and Schedule 220 Standard Daily Offer once the final TAM rates have been posted and are known. The final TAM 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 627,000 customers, and would result in an overall annual rate decrease of approximately $14.7 million or 1.2 percent. Residential customers using 850 kWh per month would see a monthly bill decrease of $0.91 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 825 NE Multnomah Street, Suite 2000 Portland, OR 97232 oregondockets@pacificorp.com	Ajay Kumar Attorney 825 NE Multnomah Street, Suite 1800 Portland, OR 97232 Ajay.kumar@pacificorp.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 Cathie Allen at (503) 813-5934.

A copy of this filing has been served on all parties to PacifiCorp's 2019 TAM proceeding, docket UE 339. Confidential material in support of the filing has been provided to parties under Order No. 16-128. Highly confidential information in support of the filing will be provided once a modified protective order is issued by the Commission.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

cc: UE 339 Service List

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **2020 Transition Adjustment Mechanism** on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

Service List
UE 339

ALLIANCE OF WESTERN ENERGY CONSUMERS	
MYRALEIGH ALBERTO **(C) (HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 maa@dvclaw.com	BRADLEY MULLINS **(C) (HC)** MOUNTAIN WEST ANALYTICS 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 brmullins@mwanalytics.com
TYLER C PEPPLE **(C) (HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE, ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO, CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY, UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	KATHERINE A MCDOWELL **(C)(HC)** MCDOWELL RACKNER & GIBSON PC 419 SW 11TH AVE., SUITE 400 PORTLAND, OR 97205 katherine@mcd-law.com
MATTHEW MCVEE **(C)(HC)** PACIFICORP 825 NE MULTNOMAH PORTLAND, OR 97232 matthew.mcvee@pacificorp.com	
STAFF	
SCOTT GIBBENS **(C)(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308-1088 scott.gibbens@state.or.us	KAYLIE KLEIN **(C)(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 kaylie.klein@state.or.us
SOMMER MOSER **(C)(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us	

Dated this 1st day of April, 2019.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 356
Exhibit PAC/100
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Michael G. Wilding

April 2019

DIRECT TESTIMONY OF MICHAEL G. WILDING

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ATTACHED EXHIBITS

Exhibit PAC/109—Backcast Net Power Costs Study for 2017

Exhibit PAC/110—List of Expected or Known Contract Updates

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 Policy.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

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

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Utility 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 2020 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 2020 TAM compared to the final NPC in the company's previous TAM, docket UE 339 (2019 TAM);

- Describes the major cost drivers in the 2020 TAM;
- Describes modeling changes the company is proposing to increase the accuracy of the TAM;
- Provides an update on a number of provisions that were agreed to by PacifiCorp through the stipulation from the 2019 TAM; and
- Provides details on the calculation of the Company Supply Service Access Charge applicable to PacifiCorp's new load direct access program for consumers who choose new load direct access and then subsequently choose standard offer or cost-based service.

Q. Please identify the other PacifiCorp witnesses supporting the 2020 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 2020 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 2020 TAM FILING

Q. Please provide background on PacifiCorp's 2020 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 2020 TAM also includes test period forecasts for: (1) Other Revenues as stipulated in docket UE 216; (2) incremental benefits and costs related to the company's participation in the energy imbalance market (EIM) with the California Independent System Operator Corporation (CAISO); and (3) renewable energy production tax credits (PTCs). The company is filing the 2020 TAM on a stand-alone basis without a general rate case and proposes that new rates become effective on January 1, 2020.

As shown in Exhibit PAC/101, the 2020 TAM results in a decrease to Oregon rates of approximately $14.7 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 2020 TAM results in an overall average rate decrease of approximately 1.2 percent.

Q. What are the estimated NPC in the TAM for calendar year 2020?

A. The forecasted normalized total company NPC for calendar year 2020 are approximately $1.480 billion.[1] This is approximately $27.7 million higher than the forecast NPC of approximately $1.453 billion in the 2019 TAM. Details of total-company NPC for 2020 are provided in Exhibit PAC/102.

Q. Does the proposed rate decrease for the 2020 TAM reflect changes in Oregon load since the 2019 TAM?

A. Yes. The 2020 load forecast used in the company's calculation of NPC reflects an increase in Oregon load compared to the 2019 forecast loads in the 2019 TAM. Due to the increase in Oregon load, the company anticipates it will collect $4.9 million more than expected for NPC based on the rates approved in the 2019 TAM. The anticipated over-collection is included in the overall rate change for the 2020 TAM.

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

A. Yes. Exhibit PAC/103 shows the update to "Other Revenues" compared to the level set in the 2019 TAM. Projected Other Revenues are approximately $68,000 lower in

[1] PAC/101, Wilding/1, line 38.

2020.[2] 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 2020 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 2020 TAM are [redacted] million, a decrease of [redacted] million in benefits from the 2019 TAM. EIM-related costs are $0.4 million. These include capital and operations and maintenance expense not normally included in NPC, and are added to the TAM to match the benefits. The Commission approved this same treatment in the 2016, 2017, 2018, and 2019 TAMs, and it is consistent with the stipulation in docket UE 287 (2015 TAM) and Commission Order 18-421 in the 2019 TAM (UE 339).[3] Details supporting EIM benefits and costs are included in Confidential Exhibit PAC/104 and Exhibit PAC/105.

[2] 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.

[3] *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 4-6 (Oct. 01, 2014); *In the Matter of PacifiCorp, d/b/a Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 8 (Dec.11, 2015); *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 16-17 (Dec. 20, 2016); *In the Matter of PacifiCorp, d/b/a Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 15 (Nov.1, 2017); *In the Matter of PacifiCorp, d/b/a Pacific Power, 2019 Transition Adjustment Mechanism,* Docket No. UE 339, Order No. 18-421 at 8-10 (Oct. 26, 2018);

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

A. Yes. The 2020 EIM inter-regional benefit is estimated using a linear regression model based on electric market prices, natural gas market prices, EIM transfer capability, and spring oversupply conditions. The change to the forecast method in the 2020 TAM versus the 2019 TAM more accurately reflects market conditions by taking into consideration additional relevant variables. This linear regression model is expected to produce an EIM benefit forecast that is more accurately aligned with the NPC forecast as compared to the method used in the 2019 TAM. This change is discussed in greater detail later in this testimony.

Q. Please describe the treatment of renewable energy PTCs in the 2020 TAM.

A. Consistent with ORS 757.264 and the Commission's order in the 2017 TAM,[4] the 2020 TAM includes changes in its projected PTCs in this filing. Exhibit PAC/106 shows the forecast level of PTCs for 2020 compared to the level of PTCs established in the 2019 TAM. The forecast of Oregon-allocated PTCs for the 2020 test period is approximately $26.4 million, which is higher than the $10.0 million included in the 2019 TAM, resulting in a decrease to the 2020 TAM of $16.4 million. The increase in PTCs is due to repowering wind projects starting to collect PTCs for the full calendar year in the 2020 TAM.

Q. Are the benefits of the 2019 repowering projects included in the 2020 TAM?

A. Yes, the benefits included in the 2020 TAM for the 2019 repowering projects include a $2.4 million reduction to NPC and $24.1 million of PTCs. Consistent with the

[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.

stipulation that was adopted in the 2019 TAM, the 2020 TAM includes the benefits of the repowering projects that will come online in 2019.[5] This includes the repowering of 773.5 megawatts (MW) at the Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, Glenrock I, Goodnoe Hills, High Plains, McFadden Ridge, Marengo I, and Marengo II wind facilities.

Q. How are the costs of the 2019 wind repowering projects recovered in rates?

A. The 2019 wind repowering projects costs are not currently included in rates though customers are receiving the benefits as they were included in the 2019 TAM. As part of the 2019 TAM settlement, parties agreed to a process in which customers would receive the 2019 repowering benefits in the 2019 TAM and the costs would be recovered through a Renewable Adjustment Clause (RAC). This process resulted in the matching of the costs and benefits of the 2019 wind repowering projects even though the timing is not perfectly aligned. As part of this process, the company filed a RAC on December 28, 2018, rather than the April filing date set forth in Schedule 202. The unique timing of this RAC filing allows the Commission and stakeholders to review the costs of the wind repowering projects and contemporaneously include those costs in rates. However, customers are already receiving the 2019 wind repowering benefits throughout 2019, even though these projects are not yet in service and the costs will not be in rates until October or December of 2019. Although this process does not align costs and benefits in a manner consistent with the TAM Guidelines[6] or Order No. 07-572, this approach reasonably aligns costs and

[5] *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421 at 3-4 (Oct. 26, 2018).
[6] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 at 4 (Oct. 30, 2009).

benefits and avoids the need for deferral of capital costs associated with the 2019 wind repowering projects. As a result, the 2019 repowering benefits are dependent on the cost recovery of those repowering projects through the RAC (Docket No. UE 352).

Q. How are the impacts of the 2020 repowering projects included in the 2020 TAM?

A. PacifiCorp proposes to include in the TAM the benefits (including PTCs) of the Glenrock III wind repowering project, which is expected to come online in summer 2020. Similar to the treatment of the 2019 wind repowering projects in the 2019 TAM, this will provide immediate benefits to customers. PacifiCorp also proposes a RAC process for Glenrock III similar to the process used for the 2019 wind repowering projects. In contrast, PacifiCorp proposes to reflect both the costs and benefits of the Dunlap wind repowering project, which is expected to come online in December 2020, in an upcoming general rate case. This will minimize rate changes for customers and will also result in PacifiCorp absorbing the impact of regulatory lag for recovery of this project. PacifiCorp's proposed treatment for Glenrock III and Dunlap repowering projects is described below.

Q. How is PacifiCorp proposing to treat the Glenrock III repowering project?

A. The Glenrock III repowering project comes online in the summer of 2020. PacifiCorp proposes to provide customers the benefits, including PTCs, associated with Glenrock III in the 2020 TAM, similar to how the benefits of the 2019 wind repowering projects were included in the 2019 TAM. PacifiCorp also requests the ability to file a RAC in early 2020 for the recovery of costs associated with Glenrock III, consistent with the cost recovery treatment approved by the Commission for the

2019 wind repowering projects in the 2019 TAM. This enables reasonable matching of costs and benefits in customer rates. The benefits for the Glenrock III repowering project are projected to be $0.6 million in the 2020 test year.

Q. What action is required by the Commission in order for PacifiCorp to provide these benefits to customers?

A. PacifiCorp again requests modification of the timing for filing a RAC, as approved in Order No. 07-572,[7] and set forth in PacifiCorp's Schedule 202. This modification would allow PacifiCorp to file a RAC on January 2, 2020, that reflects a rate effective date of August 1, 2020, contemporaneous with the expected in-service date of the Glenrock III repowering project. If these benefits are included in the 2020 TAM, PacifiCorp again reserves the right to adjust the NPC and PTC benefits if any portion of this repowering project is disallowed in a RAC filed in 2020 to ensure that costs and benefits remain matched.

Q. How is the Dunlap repowering project treated in the 2020 TAM?

A. The Dunlap repowering project is not included in the 2020 TAM because the expected in service date occurs in late-2020. This affects the ability of PacifiCorp to minimize rate changes and match the benefits and costs of the resources. PacifiCorp is planning to seek recovery of the Dunlap repowering costs in a general rate case that will have a rate effective date of January 1, 2021, and will include the benefits in rates at the same time. This treatment results in approximately one month of regulatory lag from when the asset is scheduled to come online to when the costs and benefits would be included in rates.

[7] *In the Matter of the Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 (Dec. 19, 2007).

Q. How is the Energy Vision 2020 (EV 2020) project treated in the 2020 TAM?

A. The EV 2020 project is not included in the 2020 TAM due to PacifiCorp's ability to minimize rate changes and match the benefits and costs of the resources. EV 2020 includes 1,311 MW of new wind assets at TB Flats, Cedar Springs II, Ekola Flats, Uinta, and a power purchase agreement (PPA), Cedar Springs I. In addition, EV 2020 also includes a new 140 mile, 500 kilovolt transmission line between the Aeolus substation and the Jim Bridger power plant to allow the interconnection of these facilities into PacifiCorp's transmission system. Consistent with the treatment of new resources described in the TAM guidelines, these impacts are excluded because these assets will not be in service prior to April 1 of 2020.[8] These assets will only be in service in November or December of 2020, and PacifiCorp is planning to seek recovery in a general rate case that will have a rate effective date of January 1, 2021. This treatment results in approximately one month of regulatory lag from when the asset is scheduled to come online to when the costs and benefits would be included in rates.

Q. Why is Cedar Springs I not included in the 2020 TAM?

A. Cedar Springs I is a new wind resource PPA included in EV 2020. The Aeolus-to-Bridger transmission line is necessary to incorporate Cedar Springs I into PacifiCorp's system and for customers to realize the benefits of this resource. Consistent with the matching of costs and benefits, and the treatment of the other components of the EV 2020 project this PPA is not included in the 2020 TAM.

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

Q. How is the Cedar Springs III PPA treated in the 2020 TAM?

A. PacifiCorp recently signed a PPA with NextEra for an additional 120 MW of wind at the Cedar Springs III project. This PPA is expected to be in-service in the fourth quarter of 2020. Although the Cedar Springs III project is not part of EV 2020, it depends on the Aeolus-to-Bridger transmission line described above to incorporate this resource into PacifiCorp's system and realize benefits for customers. As a result, the impacts of this PPA have also been excluded from the 2020 TAM to match the costs and benefits of this project.

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.[9]

Q. Please explain how PacifiCorp calculates NPC.

A. PacifiCorp calculates NPC for a future test period based on projected data using

[9] *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).

GRID, which is a production cost model that simulates the operation of the company's power system on an hourly basis.

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

A. Yes. 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 2020 TAM?

A. No. PacifiCorp used the same version of the GRID model in the 2020 TAM that it used in the 2019 TAM, subject to the following modeling refinements: updated scalars for the Official Forward Price Curve (OFPC), updated shaping for solar generation, and updated GRID topology to split the Wyoming Northeast bubble into a Wyoming East and Wyoming North bubble.

Q. What inputs were updated for this filing?

A. The company updated all inputs to the 2020 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 OFPC the company used in this filing?

A. PacifiCorp's filing uses an OFPC dated December 31, 2018.

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 and light load hours.

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 purchase power expense, coal fuel expense, and wheeling expense. Figure 1 illustrates the change in total-company NPC by category from the NPC baseline in the 2019 TAM.

Figure 1
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2019	**$1,452**	**$24.62**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	140	
Purchased Power Expense	(43)	
Coal Fuel Expense	(73)	
Natural Gas Fuel Expense	6	
Wheeling and Other Expense	(3)	
Total Increase/(Decrease) to NPC	**28**	
OR TAM 2020	**$1,480**	**$24.77**

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower sales volumes. The reduction is partially offset by the higher average market prices during 2020. Total wholesale sales revenue is $139.7 million lower than the 2019 TAM which includes a $138.7 million decrease in revenue from market transactions (represented in GRID as short-term firm and system balancing sales). Market sales transactions in the 2020 TAM are 4,709 gigawatt-hours (GWh) lower than in the 2019 TAM. The wholesale sales market prices in the 2020 TAM use an average price of $30.89/megawatt-hour (MWh), while what was included in the 2019 TAM used an average price of $30.46/MWh, a one percent increase.

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 2020 TAM is 2,071 GWh lower than the 2019 TAM. Market purchases in the current case are included at an average price of $25.31/MWh, while the 2019 TAM used an average price of $25.58/MWh.

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 $13.2 million (total-company) compared to the 2019 TAM. The increase is attributed to several solar QFs in Oregon and Utah that have reached a full year of commercial operation.

Several solar PPAs are also included in 2020 TAM, however, the cost impacts of these solar PPAs in 2020 TAM are minimal due to the expected commercial operational dates happening at the end of the test period 2020.[10]

Q. Did the company apply the contract delay rate (CDR) approved by the Commission in the 2018 TAM?[11]

A. Yes. As described in more detail below, the QF PPA costs included in the 2020 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 from the last three TAM proceedings. The average days delayed is weighted by the nameplate capacity of the delayed QF in the historical period.

[10] There are six new solar PPAs: five of them have a COD of December 31, 2020 and one has a COD of November 30, 2020.
[11] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 17 (Nov. 1, 2017).

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 $73 million lower than the 2019 TAM due to the lower coal generation volume at the company's coal plants. The average coal prices are $0.19/MWh higher than the prices in the last TAM. The increase 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 2019 TAM.

A. Natural gas fuel expense in the 2020 TAM is $6.3 million higher than the natural gas fuel expense in the 2019 TAM, a two percent increase. The higher gas fuel expense in this TAM is due to the greater natural gas generation volume. The increase is partially offset by the lower natural gas market prices. The average cost of natural gas generation decreased from $19.89/MWh in the 2019 TAM to $18.56/MWh in the current case, a seven percent decrease. Generation from natural gas plants in the 2020 TAM is 1,429 GWh (nine percent increase) more compared to the 2019 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 Bonneville Power Administration (BPA) BP-20 rates case. The company's initial filing incorporates BPA October 31, 2018 Partial Settlement Agreement Proposal Rates for the 24-month period beginning October 2019, which decreases wheeling expense approximately $2.3 million.

Q. How are Jim Bridger Units 3 and 4 modeled in the 2020 TAM?

A. In PacifiCorp's 2020 TAM, the minimum operation levels of Jim Bridger Units 3 and 4 stay 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 prior TAM proceedings and minimize the number of contested issues.

Q. What updates are expected in the company's resource portfolio relative to the 2019 TAM?

A. The company updated minimum operation level for several thermal plants. The impacts are included in Step 3 of Exhibit PAC/107, the Step Log.

Q. How is Naughton Unit 3 treated in the 2020 TAM?

A. Naughton Unit 3 was taken offline January 31, 2019, and therefore is not included in the 2020 TAM initial filing. To the extent the 2019 Integrated Resource Plan (IRP) identifies conversion of Naughton Unit 3 to natural gas as part of the preferred portfolio, the impacts will be included in an update to the 2020 TAM.

Q. Does the company model coal economic cycling in the 2020 TAM?

A. The company followed the same logic for the economic coal cycling as it did in the 2019 TAM which allows Cholla 4 and Hunter 1 to cycle economically during the cycling period from February 1 to May 31 in the 2020 TAM. Hunter unit 2 was previously allowed to cycle but is now an EIM participating unit and therefore not allowed to economically cycle in GRID for purposes of the 2020 TAM.

Q. What is the impact of the economic cycling to the 2020 TAM, as compared to the 2019 TAM?

A. The economic cycling of coal plants reduced NPC by $1.5 million on a total-company basis from the 2019 TAM.

Q. Was the Day Ahead/Real Time (DA/RT) adjustment calculated in a manner that is consistent with the 2019 TAM?

A. Yes, the DA/RT adjustment calculated in this filing was calculated with the same methodology that was used in the 2019 TAM.

Q. What is the impact of the DA/RT adjustment to the 2020 TAM, as compared to the 2019 TAM?

A. The DA/RT adjustment in the 2019 TAM is approximately $0.81 million (total-company) higher than the DA/RT adjustment approved by the Commission in the 2019 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 2019 TAM?

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

- Updated scalar method for the OFPC;
- Updated solar hourly shape; and,
- Updated topology splitting the Wyoming Northeast bubble.

Additionally, the company updated the EIM benefits modeling. 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.[12] PacifiCorp's proposed modeling changes improve the accuracy of the company's NPC forecast.

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 2020 TAM. This notice was provided on March 1, 2019 and is included as Exhibit PAC/108.

[12] *See 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).

Updated Scalars to the Official Forward Price Curve

Q. Please briefly describe the scalars and how they are applied to the OFPC the company used in GRID.

A. Scalars are multipliers that are applied to the monthly prices from the OFPC to derive an hourly price profile or in other words to give the monthly prices an hourly shape. These multipliers are unique for every hour in a month for a given day type (i.e., weekdays excluding holidays, Saturdays excluding holidays, and Sundays/holidays), and therefore yield hour-to-hour price variability that is consistent with historical price data. Scalars greater than one would result in an hourly price for a given day type that is higher than the monthly forward price, and scalars that are less than one would result in an hourly price for a given day type that is lower than the monthly forward price. For example, if the average market price during hour-ending 10 in May is \$18/MWh, and the average market price during all hours in May is \$20/MWh, then the scalar for hour-ending 10 in May would be 0.9 or 90 percent.[13] The hourly price profile that is a result of applying scalars to forward monthly prices yields hourly prices that, when averaged across a given month, precisely equal the forward monthly prices in the OFPC.

Q. Please explain the change to scalars used in the 2020 TAM.

A. To better reflect ongoing changes in power markets and to increase transparency, PacifiCorp is no longer using five years of historical hourly prices from PowerDex. Instead, PacifiCorp is using the CAISO day-ahead hourly market prices at California-Oregon Border (COB) and Palo Verde (PV) for the most recent 12-month period.

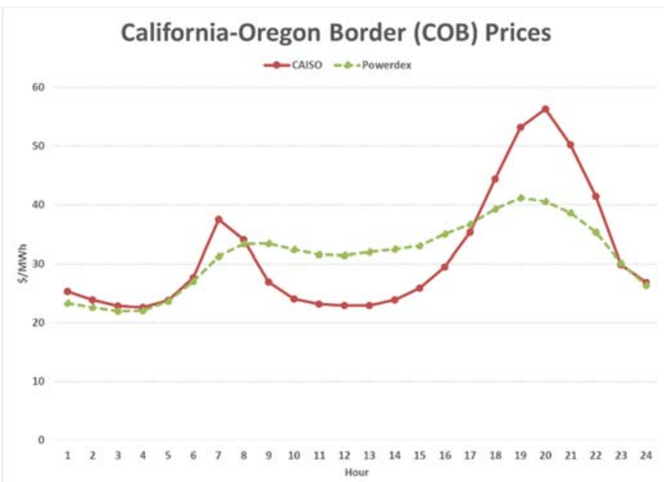
[13] \$18/MWh divided by \$20/MWh equals 0.9 or 90 percent.

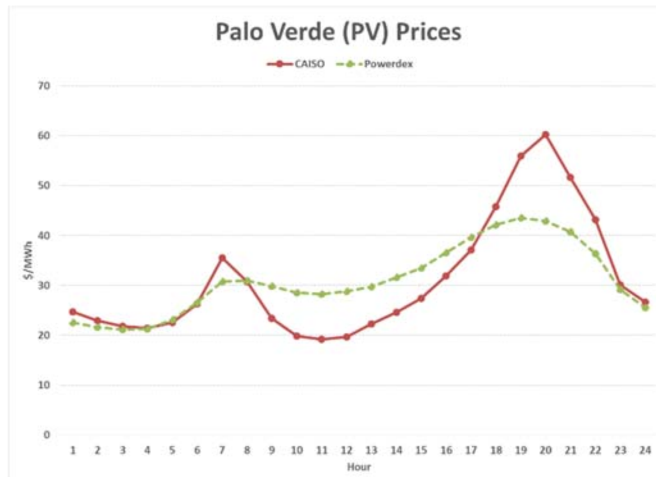
The change in data inputs that determine the scalars does not, however, alter the application of the scalars as described above.

Q. What are the hourly market price shapes using CAISO Scalars results?

A. Figure 2 shows average hourly price profiles as derived from historical PowerDex alongside hourly price profiles derived from historical CAISO data for the COB and PV market hubs, which is used in the 2020 TAM. In both charts, the hourly price profile is based on the average hourly prices for 12 months in 2020.

Figure 2





Q. Why is PacifiCorp making this change to its scalars?

A. As seen in the charts above, the updated scalars (red line) produces a more reasonable shape with a peak in the morning hours, depressed prices during mid-day, and larger peak in the evening hours. This type of shape is expected given the solar penetration in the west and is the result of higher quality CAISO trade data that better reflects actual and ongoing conditions in the power markets. The volume of actual trade data reported from CAISO is substantially higher than the volume of actual trade data that is reported in PowerDex. The use of the CAISO trade data results in scalars that better represent the increasing solar capacity in California and price volatility on a day-ahead basis. PowerDex is based on hour-ahead trade data, and in 2017, only 5.6 percent of the company's short-term firm transactions were hourly trades. Finally, the historical CAISO day-ahead hourly prices are publicly available resulting in greater transparency compared to the proprietary PowerDex prices.

Q. Why is the use of data from the most recent 12 months reasonable?

A. The scalars give the monthly prices an hourly shape and the most recent 12 months is indicative of the hourly shapes the company expects to see in the markets in the future. Both PacifiCorp and the western interconnect as a whole have experienced a significant increase in the number of solar resources, including additional solar resources in the last 12 months, and this trend is expected to continue over the next several years.[14] This trend of increased solar resources has a meaningful impact on market price shape and the use of a five-year average dulls the impact of this trend. This effect can been seen in Figure 2 above as the green line is much flatter. In other words, the hourly shape of power prices over the past five years is not an accurate representation of the hourly shape expected in the future given the impact of solar resources. Additionally, using one year of data to provide a shape is consistent with how the company shapes the wind generation and how the company is proposing to shape the solar generation in this proceeding.

Q. Are there considerations in the calculations of hourly scalars for very high or very low price variations?

A. Yes. CAISO prices can vary widely, and the price shape for an hour and month can be skewed by the presence of a few very high or very low prices. Therefore, the

[14] U.S. ENERGY INFORMATION ADMINISTRATION. ANNUAL ENERGY OUTLOOK 2017, Tables 58.19-58.22, *available at* https://www.eia.gov/outlooks/aeo/tables_ref.php.

CAISO prices used to calculate the hourly scalars are capped to limit the impact of potentially more extreme results. Large price variations are generally a result of unexpected conditions, which can include significant deviations from forecasted load, wind, or solar. Such deviations are largely random, so the presence of extreme values is generally a chance occurrence, rather than a characteristic of a given hour. Therefore, the CAISO prices used to calculate the scalars are capped at +$250/MWh and -$50/MWh. This balances the evidence that extreme events did occur in particular hours, with the likelihood that such events could occur in any hour.

Additionally, as the historical monthly prices approach zero, the magnitude of the shaping becomes unrealistically large. When this happens, the historical prices are uniformly shifted until the average monthly price over the calculation period is $25/MWh, then the scalars are calculated based on the adjusted historical prices resulting in a more reasonable shape.

Q. What is the NPC impact of the change to the scalars?

A. This change increased NPC by $1.2 million.

Updated Solar Hourly Shape

Q. Please explain how the company used historical solar output to calculate the solar generation profile in this case.

A. Solar generation is included in GRID based on a "P50" forecast.[15] A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast. Typically such a forecast is developed for an individual project by combining solar exposure taken before the project is constructed

[15] PacifiCorp does not currently have sufficient historical data available to reflect solar generation in GRID on a historical actual average basis. In the absence of historical data, the use of a P50 forecast is appropriate.

with a detailed plant location and performance characteristics. The projected output in a given hour is then averaged across each month to develop a 12 x 24 matrix of average hourly output. The company has historically input solar generation into GRID using the P50 forecast divided into 24 sessions per month resulting in the same generation each day in a particular month. Consequently, the solar generation in GRID exhibited very little variation, contrary to solar generation's inherently variable nature.

In this case, the company continues to use the P50 forecast approach for determining total solar generation, but used the company's actual 2017 energy output data from its purchased solar facilities to shape hourly solar generation profiles. The company scaled actual generation levels up or down so that, when the output is averaged over the course of a month, it is the same as in the P50 forecast. In other words, the total energy output of the solar facilities is the same as the P50 forecast used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2017. This method is consistent with the wind hourly shape method approved by the Commission in the 2014 TAM proceeding.[16]

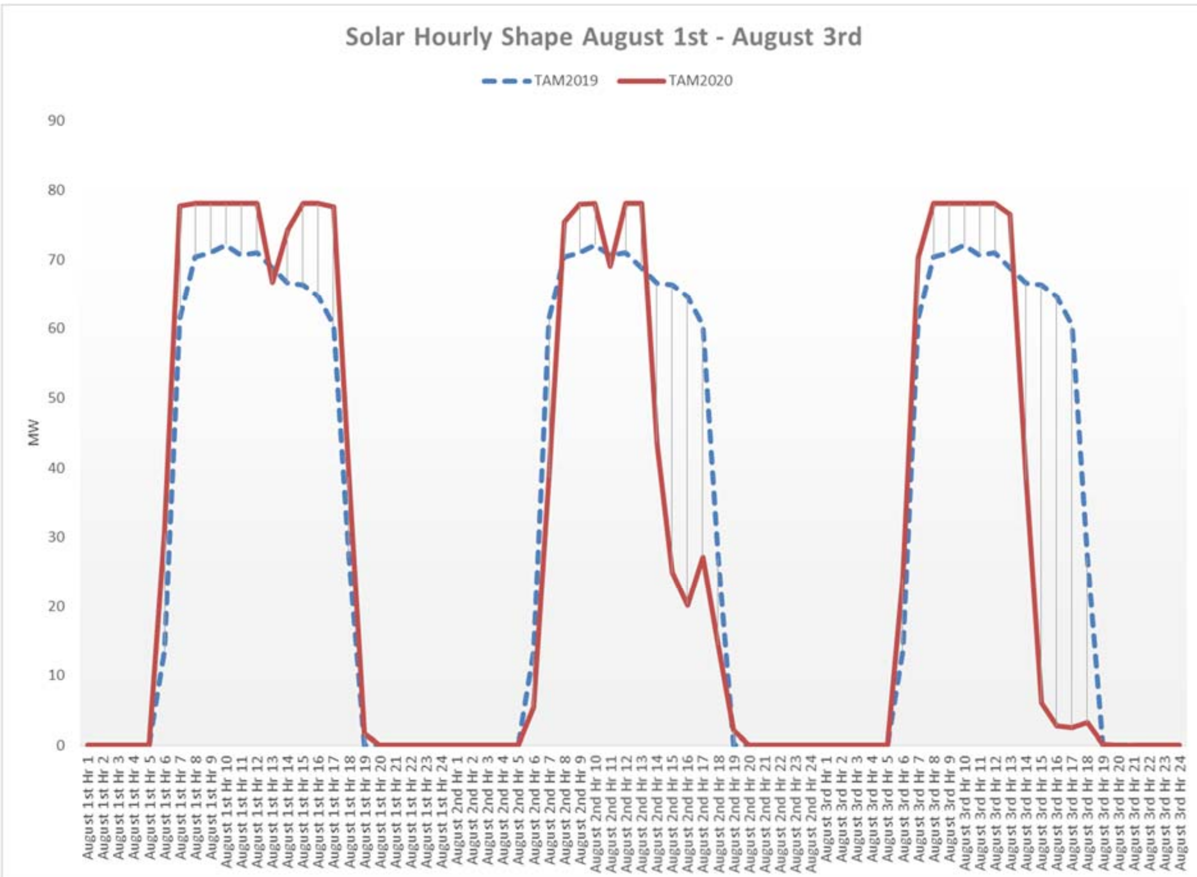
Q. Why did the company refine the modeling of its hourly solar profiles to reflect historical performance?

A. Figure 3 illustrates the difference in solar generation profiles. The solid line shows one solar plant's hourly energy shape on the dates August 1st to August 3rd in the 2020 TAM. The dashed line shows the solar hourly profile for the same dates in the 2019 TAM. The shaded area shows the difference between the two hourly shapes

[16] *In the Matter of PacifiCorp d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 2-4 (Oct. 28, 2013).

and represents the difference of the solar generation for that day. The dashed line does not have any day-to-day variation in each month. The solid line better represents the solar inputs that vary hourly based on historical volatility, with the same total monthly solar generation volume as the P50 forecast.

Figure 3



Clearly, an average solar generation forecast shaped over a flat daily period does not capture the actual variability associated with solar generation on PacifiCorp's system. Applying the 2017 actual solar generation pattern to the total average solar generation P50 volumes improves the accuracy of forecasted NPC by capturing the cost impacts associated with intermittent solar generation on an hourly basis using the most recent reliable data available.

Q. What is the impact of updating the hourly solar shape to the company NPC?

A. In this case, reflecting the generation output as described above increases NPC approximately $237,000.

Splitting the Wyoming Northeast Bubble

Q. Why is the company proposing the change to the Wyoming Northeast Transmission Bubble?

A. Historically, the Wyoming Northeast area was treated as one transmission bubble in the GRID model. The GRID model assumes that any resource within a specified transmission area can serve any load within the transmission area and can be exported on any transmission link from that transmission area. Due to the increasing amount of renewable resources in the Wyoming Northeast area, the company proposes to split the Wyoming Northeast Bubble into Wyoming North and Wyoming East bubbles to better reflect transmission constraints in the area.

Q. What is the basis for splitting the Wyoming Northeast transmission into the Wyoming North and Wyoming East transmission area?

A. The transmission rights within GRID reflect the company's transmission reservations. To capture the effect of constraints that limit the ability of certain resources to reach certain loads or to be exported on certain paths, those constraints must be represented in the GRID model as a separate transmission area.

Q. Does the splitting of the Wyoming Northeast bubble require any load values restructure?

A. No. The company's load forecast includes distinct hourly values for Wyoming North and Wyoming East loads, and those values have previously been aggregated before being included in the GRID model. As a result, incorporating separate load values for Wyoming North and Wyoming East does not require any analysis or assumptions change to the load.

Q. What is the impact of this change?

A. This change decreases NPC by $4,403, and it will allow for a more accurate modeling of the system.

EIM Costs and Benefits

Q. Has the EIM continued to provide customer benefits?

A. Yes. PacifiCorp has participated in the EIM since 2014, and has included EIM benefits in each TAM filing since that time. As shown in Confidential Figure 4 below, EIM benefits have increased each year, primarily as a function of increased market participation, but as participation has slowed[17] and the market has matured, prevailing market prices have been shown to be the primary driver of EIM benefits.

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

A. Consistent with past modeling of EIM benefits, PacifiCorp's 2020 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 flexibility reserves. As shown in Confidential Figure 4, the 2020 TAM includes approximately [redacted] million of EIM benefits on a total-company basis.

[17] CALIFORNIA INDEPENDENT SYSTEM OPERATOR, CALIFORNIA ISO WESTERN EIM BENEFITS REPORT FOURTH QUARTER at 3-4 (Jan. 31, 2019) *available at* https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ4-2018.pdf.

Confidential Figure 4

Total-Company EIM-Related Benefits and Costs

$ millions	2015 TAM	2016 TAM	2017 TAM	2018 TAM	2019 TAM	2020 TAM
Inter-regional dispatch	[redacted]					
Flexibility Reserves						
Test-period EIM benefits						

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 security constrained unit commitment algorithm and the security constrained economic dispatch algorithm. 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 PacifiCorp's actual NPC?

A. Participation in the EIM reduces PacifiCorp'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 algorithms (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).

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

A. Using the same methodology as the 2016, 2017, 2018, and 2019 TAMs, PacifiCorp reduced the regulating reserve requirement modeled in GRID by roughly 130 MW to account for the company's share of the reserve benefit based on the diversified footprint of the EIM. The methodologies for determining the reduction in reserves associated with the participation of CAISO, Nevada Energy, Arizona Public Service Company, Puget Sound Energy, Portland General Electric, Idaho Power Company, PowerDex, and the Balancing Authority of Northern California in the EIM are unchanged from the 2019 TAM. The overall reduction in the company's reserve requirement from its participation in EIM decreases NPC by approximately $1.6 million on a total-company basis.

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

A. The inter-regional transfer benefit reflects the benefit received by PacifiCorp when it economically exports 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 MWh 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. How has the methodology used to calculate the inter-regional EIM benefits in the 2020 TAM changed?

A. Using EIM benefits by month, a linear regression model was developed utilizing the following four independent variables: electric market prices, natural gas market prices, EIM transfer capability, and spring oversupply conditions.

The 2019 TAM EIM Benefits methodology also used a linear regression model, but the only independent variable was time, and it did not capture all the variables that actually impact inter-regional EIM benefits. Though this type of regression analysis was appropriate considering the continued growth of the EIM through new participants, as that growth stabilizes, the use of more independent variables provides a more robust and accurate view of the future.

Q. Will the forecast model for inter-regional EIM benefits be more accurate if it includes market prices, EIM transfer capability and oversupply conditions?

A. Yes. The linear regression model with multiple independent variables will more accurately reflect market conditions which drive EIM benefits resulting in a more accurate forecast. The increased accuracy of the 2020 TAM model is illustrated by the “fit” of the model with historical EIM Benefit data in Confidential Figure 5 below as compared to the 2019 TAM forecast.

Confidential Figure 5

[redacted]

Q. Please explain the "fit" of the model mentioned above.

A. The blue line is the actual margins or the actual EIM benefits realized by the company. The TAM 2020 line represents the results of the linear regression model used in the 2020 TAM. For the historical periods the company used actual market prices, transmission capacity, and over-supply conditions and compared the results of the regression to the actual EIM benefits. As seen in the chart above, the 2020 TAM line matches up very well with the actual EIM benefits line.

Q. Why is it appropriate to use market prices in the forecast of EIM benefits?

A. For example if market prices are high, due to high loads, low water conditions, or transmission constraints, among other things, EIM export benefits will be higher. Similarly, if market prices are low, due to lower loads, no transmission constraints or normal water conditions, then EIM export benefits will be lower. In addition, using the market prices as a predictor of EIM benefits more closely aligns the expected benefits with the rest of the NPC forecast in GRID. In other words, by expressing EIM benefits as a function of market prices, the costs incurred to serve system load and the EIM benefits are better matched. For example, the company is required in EIM to show it has sufficient resources on its own to serve its load every hour, and in a period of high market prices the company may need to purchase energy at those higher prices to balance the system. However, within the hour when the EIM is optimized, the company can realize greater benefits from exporting energy in the EIM than it would during lower priced periods.

COMPLIANCE WITH 2019 TAM STIPULATION

Q. Were there any requirements for the 2020 TAM that were agreed to as part of the stipulation that was adopted in the 2019 TAM?

A. Yes, in Order No. 18-421, the Commission adopted the stipulation reached between the parties, which required the following actions to be completed:

- PacifiCorp agreed to develop "an alternative analysis that evaluates the reasonableness of the company's fueling strategy for the Jim Bridger plant based on a January 1, 2030 useful life for the plant." PacifiCorp agreed to "address any resulting changes to the Jim Bridger Long-Term Fueling Plan in the 2020 TAM in or before April 2019."[18]
- PacifiCorp agreed to "provide workpapers in future TAM filings to support the depreciable lives of [Bridger Coal Company] assets."[19]

[18] Order No. 18-421 at Appendix A, pg. 5.
[19] Order No. 18-421 at Appendix A, pg. 6.

- PacifiCorp agreed "to perform an additional year of GRID Model validation using a 2017 base year and the methodology described in PacifiCorp's Initial Filing."[20]

My testimony addresses the requirement to complete an additional year of GRID Model Validation further below. Mr. Ralston's testimony addresses the alternative analysis for the Jim Bridger Long-Term Fuel Plan and the provision of workpapers to support the depreciable lives of Bridger Coal Company assets.

Q. Are there any other issues from the stipulation as adopted in the 2019 TAM that need to be addressed?

A. Yes, PacifiCorp is proposing to continue the treatment that was agreed to in the stipulation for the 2019 TAM for the Capacity Factor for owned wind plants and the calculation of the Consumer Opt-Out Charge.

Model Validation

Q. Did the company perform an additional year of GRID model validation as agreed to in the 2020 TAM Stipulation?

A. Yes, PacifiCorp performed an additional year of GRID model validation consistent with the provisions agreed to in the 2019 TAM Settlement.

Q. Were the parameters for the model validation process consistent with those used for the model validation process conducted for the 2019 TAM?

A. Yes, the model validation process that was conducted was consistent with the model validation process outlined in my testimony from the 2019 TAM.[21]

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

[20] Order No. 18-421 at Appendix A, pg. 6.
[21] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Direct Testimony of Michael G. Wilding at 17-20 (Mar 30, 2018).

reasonably and accurately simulate historical NPC for the period of 2017. The GRID model estimated total company 2017 NPC to be $1,525 million compared to actual costs of $1,530 million, a variance of $4.7 million or 0.3 percent. The 2017 backcast NPC study is included as Exhibit PAC/109.

Capacity Factor for Owned Wind Plants

Q. Is it appropriate to use historical generation to calculate wind capacity factors in the TAM?

A. Yes. PacifiCorp maintains that a cumulative average methodology for company-owned wind plants with historical generation greater than four years results in the most accurate forecast of wind generation for purposes of forecast NPC.

Q. Has the Commission addressed using historical generation in calculating wind capacity factors in the past?

A. Yes, in the 2016 TAM the Commission concluded that "[f]orty-eight months of actual operation is sufficient for deriving a reasonable forecast of expected wind generation at a site *that is superior to the long-range forecast provided by the project owners*."[22] In other words, the Commission found that actual historical data produced a more accurate NPC forecast for wind PPAs, which is consistent with the purpose of the TAM.

Q. Is it appropriate to update wind capacity using the best available information?

A. Yes. The purpose of the TAM is to "produce the best possible estimates of all components of net power costs."[23] Therefore, if better information is available it

[22] *In the Matter of PacifiCorp d/b/a Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 7 (Dec. 11, 2015) (emphasis added).
[23] *In the Matter of PacifiCorp 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).

should be used in ratemaking regardless of the information used during the planning process. The Commission also rejected the use of outdated planning assumptions for ratemaking in Order No. 08-548:

> Although the estimated capacity factor at the time of project approval is dispositive for purposes of prudency review, it is not dispositive for purposes of forecasting resource availability for ratemaking purposes. The most recent reliable data should be used to set rates for the test period, recognizing that such data necessarily will be uncertain, particularly at start-up.[24]

While it is true that the best available information at the time the wind resources were built was the P50 forecasts, we now have approximately 10 years of experience at each facility to inform a more accurate NPC forecast. Notably, in the 2017 IRP and the 2017 IRP update, which included repowering as part of the preferred portfolio, the wind capacity factors were based on a historical average.

Q. Please described the history of the forecast capacity factor for owned wind plants.

A. Up until the 2019 TAM, the generation from PacifiCorp's owned wind plants was based on long-range forecasts done at the time of the project development referred to as the P50 forecast. In the 2019 TAM, PacifiCorp proposed to calculate the annual capacity factor using a cumulative historical average methodology for any wind plant with a history of generation longer than four years.

In the stipulation that settled the 2019 TAM, PacifiCorp agreed "to forecast the net capacity factor for company-owned wind projects using a 50/50 blend of (1) the P50 production estimates when each wind project was initially developed, and

[24] *In the Matter of PacifiCorp 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 21 (Nov. 14, 2008).

(2) the cumulative average methodology proposed by PacifiCorp" in the 2019 TAM. The parties agreed that this was a one-time, non-precedential adjustment.[25]

Q. How is PacifiCorp proposing to treat the forecast capacity factor for owned wind plants in this TAM?

A. Although use of the cumulative average methodology originally proposed in the 2019 TAM is the most accurate method to forecast the capacity factor for company-owned wind projects, in the interests of minimizing contested issues, PacifiCorp has filed the 2020 TAM using the same forecast for the capacity factor that was agreed to in the 2019 TAM stipulation.

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 Charge 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.[26] The Commission affirmed the Consumer Opt-Out Charge in the 2016, 2017, and 2018 TAMs.[27] As part of a non-precedential provision in the stipulation for the 2019 TAM, PacifiCorp agreed to not apply inflation to the fixed generation costs in years six through 10.

[25] Order No. 18-421 at Appendix A, pg. 5.
[26] *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).
[27] Order No. 15-394 at 12; Order No. 16-482 at 23; Order No. 17-444 at 20.

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 holds that cost flat through year 10 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 pay PacifiCorp's fixed generation costs for 10 years (offset by the value of freed-up energy).

Q. How is calculation of the Consumer Opt-Out Charge in the 2020 TAM different from previous TAMs?

A. Before the settlement in the 2019 TAM, PacifiCorp escalated the year five Schedule 200 cost through year 10, using an inflation escalator, to develop a forecast of Schedule 200 costs for years six through 10.

Q. Why is it appropriate to 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. If it is appropriate to use an inflation escalator to forecast Schedule 200 costs for years six through 10 why is PacifiCorp holding Schedule 200 flat for years six through 10?

A. This has been a contested issue in the TAM for many years and although the use of an inflation escalator is the most accurate method to forecast Schedule 200 costs, in the interests of minimizing contested issues, PacifiCorp has filed the 2020 TAM proposing to calculate the Consumer Opt Out Charge using the same method, i.e.

holding Schedule 200 flat for years six through 10, that was agreed to in the 2019 TAM stipulation. Consistent with the stipulation in the 2019 TAM, this would be a non-precedential adjustment to only the 2020 TAM.[28]

COMPANY SUPPLY SERVICE ACCESS CHARGE

Q. What is the Company Supply Service Access Charge?

A. If a new customer elects new load direct access and then subsequently switches to standard offer or cost-based service, resulting in an increase to rates for existing cost-of-service customers of more than 0.5 percent, the consumer electing to switch to standard offer service or cost-based service will be subject to a four-year forward looking rate adder, the Company Supply Service Access Charge. The 0.5 percent assessment is a reasonable threshold for the Company Supply Service Access Charge that represents a material and significant impact to customers and was acknowledged by the Commission at a public meeting on February 26, 2019.[29]

Q. How is the Company Supply Service Access Charge calculated?

A. The Company Supply Service Access Charge is calculated as the incremental difference between the four-year levelized cost of capacity that is calculated for avoided cost and the fixed generation costs, Schedule 200. This calculation fairly assigns the new load direct access consumer that is switching to cost-of-service the additional fixed cost associated with the company's obligation to serve that consumer less the additional recovery that will be received from that consumer for existing fixed generation in rates. The levelized cost of capacity for the upcoming four years

[28] *See* Order No. 18-421, at Appendix A pg. 8.
[29] *PacifiCorp Schedule 193 New Large Load Direct Access Program*, Docket No. ADV-900, Advice No. 18-010, acknowledged Feb. 26, 2019.

is currently less than the fixed generation costs contained in Schedule 200 and therefore the Company Supply Service Access Charge is $0/MWh.

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, with the exception of the PPAs from EV 2020 and the Cedar Springs III PPAs as described earlier in this testimony.

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

A. Yes. Exhibit PAC/110 contains a list of known contracts and other items that could be included in the company's TAM updates in this case based on the best information available at the time the company prepared the NPC study.

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

A. In compliance with Attachment B to the TAM Guidelines, the company provided access to the GRID model and workpapers concurrently with this initial filing. Specifically, the company 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/107.

Q. Did the company provide pre-filing notice to the parties of modeling and input changes in the 2020 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 2020 TAM, provided on March 1, 2019, is included as Exhibit PAC/108.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 356
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

April 2019

PacifiCorp
CY 2020 TAM
Intial Filing

			Total Company					Oregon Allocated	
			UE-339	TAM				UE-339	TAM
Line no		ACCT.	CY 2019 - Final Update	CY 2020 - Initial Filing	Factor	Factors CY 2019	Factors CY 2020	CY 2019 - Final Update	CY 2020 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	7,967,439	7,010,945	SG	26.725%	26.456%	2,129,283	1,854,805
3	Existing Firm UPL	447	-	-	SG	26.725%	26.456%	-	-
4	Post-Merger Firm	447	478,486,284	339,748,239	SG	26.725%	26.456%	127,874,540	89,883,268
5	Non-Firm	447	-	-	SE	25.322%	25.314%	-	-
6	**Total Sales for Resale**		486,453,723	346,759,184				130,003,823	91,738,073
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	3,133,795	4,795,373	SG	26.725%	26.456%	837,501	1,268,656
10	Existing Firm Demand UPL	555	3,332,695	3,793,638	SG	26.725%	26.456%	890,656	1,003,639
11	Existing Firm Energy	555	17,662,229	21,667,704	SE	25.322%	25.314%	4,472,499	5,485,049
12	Post-merger Firm	555	721,894,615	672,350,836	SG	26.725%	26.456%	192,924,948	177,876,096
13	Secondary Purchases	555	-	-	SE	25.322%	25.314%	-	-
14	Other Generation Expense	555	7,099,964	7,455,847	SG	26.725%	26.456%	1,897,452	1,972,507
15	**Total Purchased Power**		753,123,297	710,063,398				201,023,056	187,605,948
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	22,380,362	22,079,714	SG	26.725%	26.456%	5,981,109	5,841,375
19	Existing Firm UPL	565	-	-	SG	26.725%	26.456%	-	-
20	Post-merger Firm	565	108,553,771	107,547,012	SG	26.725%	26.456%	29,010,787	28,452,471
21	Non-Firm	565	4,447,418	3,175,158	SE	25.322%	25.314%	1,126,193	803,772
22	**Total Wheeling Expense**		135,381,551	132,801,884				36,118,088	35,097,618
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	702,622,248	642,746,510	SE	25.322%	25.314%	177,920,783	162,707,412
26	Fuel Consumed - Coal (Cholla)	501	40,481,392	27,072,484	SE	25.322%	25.314%	10,250,858	6,853,236
27	Fuel Consumed - Gas	501	5,440,263	5,823,881	SE	25.322%	25.314%	1,377,605	1,474,280
28	Natural Gas Consumed	547	293,704,139	299,969,224	SE	25.322%	25.314%	74,372,923	75,935,404
29	Simple Cycle Comb. Turbines	547	3,736,769	3,426,472	SE	25.322%	25.314%	946,239	867,391
30	Steam from Other Sources	503	4,597,639	4,676,489	SE	25.322%	25.314%	1,164,232	1,183,825
31	**Total Fuel Expense**		1,050,582,449	983,715,060				266,032,640	249,021,549
32									
33	TAM Settlement Adjustment**		(545,317)	-		As Settled		(141,911)	-
34									
35	**Net Power Cost (Per GRID)**		1,452,088,257	1,479,821,158				373,028,051	379,987,042
36									
37	Oregon Situs NPC Adustments		501,570	513,798	OR	100.000%	100.000%	501,570	513,798
38	**Total NPC Net of Adjustments**		1,452,589,826	1,480,334,955				373,529,620	380,500,839
39									
40	Non-NPC EIM Costs*		3,079,748	1,572,036	SG	26.725%	26.456%	823,057	415,895
41	Production Tax Credit (PTC)		(37,465,734)	(99,704,458)	SG	26.725%	26.456%	(10,012,645)	(26,377,657)
42	**Total TAM Net of Adjustments**		1,418,203,840	1,382,202,533				364,340,032	354,539,078
43									
44								Increase Absent Load Change	(9,800,954)
45									
46	Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-339							$364,340,032	
47	$ Change due to load variance from UE-339 forecast							4,921,525	
48	2020 Recovery of NPC (incl. PTC) in Rates							$369,261,556	
49	*EIM Benefits for the 2020 TAM are reflected in net power costs								
50	**TAM Settlement UE 339 - Partial Sipulation agreed to decrease Oregon-allocated NPC by $141,911							**Increase Including Load Change**	**(14,722,479)**
51									
52								Add Other Revenue Change	67,946
53									
54								**Total TAM Increase/(Decrease)**	**$ (14,654,533)**

Docket No. UE 356
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

April 2019

PacifiCorp

ORTAM20 NPC CONF

Net Power Cost Analysis

12 months ended December 2020	01/20-12/20	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,010,945	689,859	557,344	489,357	338,833	389,099	672,129	742,635	731,953	732,477	479,200	458,873	729,187
BPA Wind	2,561,446	259,920	313,193	289,968	168,252	209,234	159,406	106,032	110,728	142,305	211,926	268,855	321,628
Hurricane Sale	8,813	734	734	734	734	734	734	734	734	734	734	734	734
Leaning Juniper Revenue	88,241	5,662	5,479	7,528	4,498	5,656	5,807	13,819	13,156	9,806	5,980	4,954	5,895
Total Long Term Firm Sales	9,669,446	956,176	876,751	787,587	512,317	604,724	838,076	863,221	856,572	885,322	697,840	733,417	1,057,444
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	61,268,380	10,033,470	9,468,090	10,033,470	7,610,940	7,581,390	7,610,940	-	-	-	3,078,720	2,838,720	3,012,640
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	61,268,380	10,033,470	9,468,090	10,033,470	7,610,940	7,581,390	7,610,940	-	-	-	3,078,720	2,838,720	3,012,640
System Balancing Sales													
COB	46,104,002	4,499,966	4,272,688	4,522,961	3,607,632	3,935,728	2,289,767	2,256,643	4,256,468	4,664,509	3,357,521	3,793,916	4,646,202
Four Corners	51,871,277	3,748,903	3,351,227	2,722,248	2,079,061	2,674,507	2,514,980	8,769,184	7,708,656	7,027,930	4,304,382	3,201,270	3,768,929
Mead	45,128,831	4,707,428	3,907,027	1,930,282	1,619,761	1,165,346	3,405,880	2,635,528	5,498,437	5,040,018	5,322,244	5,007,663	4,889,217
Mid Columbia	45,891,563	4,198,149	3,100,868	2,735,260	2,067,677	3,055,111	1,964,786	7,200,109	8,008,142	4,757,942	3,291,866	3,235,012	2,276,641
Mona	23,760,474	2,838,999	900,769	691,299	505,163	749,395	2,293,135	2,508,159	3,374,647	4,598,903	1,790,340	1,692,329	1,817,336
NOB	5,222,619	1,764	739,074	268,450	694,069	292,197	34,625	1,285,831	1,274,991	631,619	-	-	-
Palo Verde	57,695,120	1,413,725	1,247,492	843,002	845,860	1,151,774	2,230,272	15,149,662	15,902,916	7,236,215	2,695,944	4,148,362	4,829,897
Trapped Energy	147,472	108,588	6,949	13,855	-	1,371	-	-	-	-	-	16,709	-
Total System Balancing Sales	275,821,358	21,517,522	17,526,095	13,727,357	11,419,223	13,025,428	14,733,446	39,805,117	46,024,258	33,957,137	20,762,297	21,095,260	22,228,220
Total Special Sales For Resale	346,759,184	32,507,168	27,870,936	24,548,414	19,542,480	21,211,542	23,182,461	40,668,338	46,880,830	34,842,459	24,538,857	24,667,396	26,298,304

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	806,082	-	49,462	-	106,103	116,649	107,716	150,743	131,266	61,488	82,656	-	-
Combine Hills Wind	5,392,106	373,200	468,350	548,798	548,105	467,372	399,201	450,693	380,844	359,837	371,319	456,705	567,682
Cove Mountain Solar	5,522	-	-	-	-	-	-	-	-	-	-	-	5,522
Cove Mountain Solar II	17,478	-	-	-	-	-	-	-	-	-	4,173	13,304	-
Deseret Purchase	31,716,973	2,863,752	2,348,204	2,332,171	2,474,005	2,409,871	2,844,018	2,873,619	2,873,619	2,844,018	2,392,605	2,587,476	2,873,619
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,363,115	150,613	139,233	118,590	116,670	134,398	240,245	402,632	367,412	213,183	143,145	133,684	203,311
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
Hunter Solar	10,537	-	-	-	-	-	-	-	-	-	-	-	10,537
Hurricane Purchase	148,941	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	6,247,580	517,290	505,260	517,290	521,300	517,290	521,300	501,250	529,320	529,320	529,320	529,320	529,320
Milican Solar	1,858	-	-	-	-	-	-	-	-	-	-	-	1,858
Milford Solar	326,041	-	-	-	-	-	-	-	-	-	-	13,137	312,904
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
Prineville Solar	2,264	-	-	-	-	-	-	-	-	-	-	-	2,264
Rock River Wind	5,095,508	655,201	527,014	534,974	441,661	287,465	265,265	183,629	196,416	264,393	495,489	611,007	632,994
Sigurd Solar	8,732	-	-	-	-	-	-	-	-	-	-	-	8,732
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	20,822,069	2,803,421	1,880,006	2,145,315	1,623,997	1,433,919	1,207,512	812,094	955,458	1,191,673	1,747,775	2,357,430	2,663,470
Top of the World Wind	41,669,886	5,550,388	3,820,130	4,333,284	3,336,656	2,969,901	2,451,079	1,756,423	1,911,182	2,345,982	3,590,503	4,580,644	5,023,717
Tri-State Purchase	4,066,491	828,729	815,668	819,792	794,600	807,702	-	-	-	-	-	-	-
Wolverine Creek Wind	10,316,938	762,470	922,708	1,133,737	1,045,118	791,605	843,689	671,821	642,114	753,711	831,267	962,703	955,995
Long Term Firm Purchases Total	157,908,528	16,924,990	13,896,004	14,903,877	13,428,142	12,356,160	11,299,980	10,222,884	10,407,588	10,983,511	12,608,164	14,665,374	16,211,854
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	4,812,318	440,289	513,438	516,601	744,759	785,521	619,167	284,619	165,818	145,427	142,993	176,319	277,366
QF Idaho	9,039,785	732,020	718,003	739,350	755,012	801,825	843,737	794,903	694,326	670,317	702,318	736,268	851,708
QF Oregon	54,216,622	3,106,784	3,367,057	4,077,404	5,247,347	5,767,821	5,897,654	5,787,508	5,477,236	4,899,006	4,022,739	3,179,935	3,386,130
QF Utah	10,960,570	749,850	794,917	929,868	970,006	1,066,659	1,083,414	1,010,521	1,002,172	942,756	897,995	790,653	721,760
QF Washington	292,617	-	-	-	9,513	44,679	58,343	71,859	64,590	30,886	12,746	-	-
QF Wyoming	249,822	23,214	24,006	27,089	19,682	17,700	11,318	17,118	17,717	16,317	20,199	25,302	30,160
Biomass One QF	14,977,024	1,210,032	1,427,397	1,270,508	1,559,816	969,411	954,363	1,431,306	1,191,857	1,263,564	1,249,911	1,398,039	1,050,822
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	143,378	2,987	6,842	8,355	7,170	8,222	11,671	20,868	23,995	23,824	14,434	10,041	4,970
Enterprise Solar I QF	12,790,172	629,205	788,456	988,106	1,135,259	1,278,347	1,404,078	1,597,159	1,536,597	1,200,408	972,610	710,022	549,925
Escalante Solar I QF	11,800,647	575,962	713,369	889,952	1,030,798	1,213,056	1,330,364	1,471,738	1,417,639	1,110,348	887,207	646,625	513,591
Escalante Solar II QF	11,104,089	541,414	669,019	838,337	968,014	1,147,052	1,258,546	1,388,843	1,330,382	1,047,309	831,993	604,996	478,184
Escalante Solar III QF	10,694,485	526,327	653,951	813,067	942,929	1,117,277	1,227,758	1,350,547	1,290,901	1,017,498	761,428	554,461	438,340
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,361,116	515,285	866,754	745,168	788,454	483,154	522,325	625,934	591,857	743,010	732,178	871,508	875,489
Foote Creek III Wind QF	1,742,230	216,919	174,011	218,302	143,046	89,735	83,416	88,507	98,280	101,095	169,997	177,284	181,638
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	11,084,598	558,297	643,875	901,031	1,003,509	1,176,290	1,281,912	1,364,359	1,283,850	992,426	822,717	585,218	471,114
Granite Mountain West Solar QF	7,344,916	369,404	426,514	599,000	665,754	778,994	849,690	904,914	851,560	656,067	544,532	386,998	311,488
Iron Springs Solar QF	11,381,994	644,229	694,013	903,013	1,031,635	1,148,681	1,306,627	1,374,749	1,343,796	1,020,316	829,581	582,212	503,143
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,708,539	1,011,726	950,837	1,122,669	897,120	856,897	745,979	673,722	567,152	616,686	802,754	706,758	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	9,102,733	1,446,879	1,096,826	876,503	703,941	484,210	512,295	418,955	448,834	461,812	689,229	921,902	1,041,346
Mountain Wind 2 QF	14,207,209	2,113,279	1,644,653	1,371,849	1,095,940	758,021	923,407	777,214	747,136	769,890	1,033,054	1,430,289	1,542,480
North Point Wind QF	18,588,632	1,075,669	1,857,161	1,651,305	1,760,917	1,071,380	1,179,515	1,445,356	1,457,525	1,756,754	1,691,899	1,840,557	1,800,596
Oregon Wind Farm QF	12,943,996	752,656	1,039,810	1,148,985	1,363,047	1,295,867	1,261,905	1,312,194	1,151,716	954,443	765,973	811,538	1,085,862
Pavant II Solar QF	3,773,198	157,116	200,910	311,238	368,118	403,364	392,847	480,400	460,039	367,175	300,011	183,743	148,236
Pioneer Wind Park I QF	10,692,333	1,307,644	990,925	1,209,776	887,852	716,990	653,221	637,737	687,071	449,915	796,183	1,251,720	1,103,300
Power County North Wind QF	5,449,253	415,337	564,183	523,161	516,308	350,113	345,127	369,513	365,191	376,825	506,390	521,472	595,635
Power County South Wind QF	4,862,397	367,416	497,306	473,011	480,284	302,355	307,607	327,628	340,903	334,044	443,727	471,423	516,693
Roseburg Dillard QF	637,982	38,507	27,483	36,455	63,230	70,324	67,356	69,584	68,224	48,210	60,471	51,725	36,412
Sage I Solar QF	2,287,218	81,380	83,272	191,063	207,247	236,416	264,294	339,923	335,626	209,804	157,123	105,215	75,856
Sage II Solar QF	2,289,663	81,465	83,371	191,264	207,469	236,630	264,592	340,285	335,994	210,042	157,280	105,343	75,927
Sage III Solar QF	1,884,319	68,601	69,376	157,807	168,916	193,787	216,172	277,394	273,689	173,157	131,807	89,173	64,441
Spanish Fork Wind 2 QF	2,686,723	215,401	177,052	198,291	156,304	148,847	207,936	281,840	306,755	262,818	236,090	242,231	253,157
Sunnyside QF	30,667,985	2,699,367	2,572,985	2,629,201	1,695,831	2,662,041	2,695,401	2,707,160	2,722,633	2,597,876	2,321,412	2,682,607	2,681,471
Sweetwater Solar QF	7,873,760	262,286	391,420	569,656	695,008	820,880	993,452	1,130,956	1,047,054	822,457	635,392	301,437	203,764
Tesoro QF	494,677	39,103	37,731	59,051	35,490	70,662	21,040	29,680	28,545	38,546	36,494	37,119	61,215
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,592,999	420,587	495,052	626,242	846,984	874,824	926,714	1,066,749	1,022,891	809,146	685,359	445,103	373,347
Utah Pavant Solar QF	5,366,654	197,452	245,263	397,940	451,614	521,878	600,035	704,825	705,129	601,317	441,354	270,363	229,484
Utah Red Hills Solar QF	11,634,586	492,902	645,138	789,814	1,037,436	1,213,566	1,249,482	1,538,818	1,466,926	1,325,368	820,489	589,303	465,343
Qualifying Facilities Total	344,741,240	24,086,991	26,152,376	29,000,430	30,661,758	31,183,475	32,572,758	34,515,383	32,921,603	29,066,859	26,328,070	24,494,903	23,756,632

Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	1,995,478	166,290	166,290	166,290	166,290	166,290	166,290	166,290	166,290	166,290	166,290	166,290	166,290
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	4,474,373	372,864	372,864	372,864	372,864	372,864	372,864	372,864	372,864	372,864	372,864	372,864	372,864
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	6,469,851	539,154	539,154	539,154	539,154	539,154	539,154	539,154	539,154	539,154	539,154	539,154	539,154
Total Long Term Firm Purchases	509,119,619	41,551,136	40,587,535	44,443,461	44,629,054	44,078,790	44,411,892	45,277,422	43,868,345	40,589,525	39,475,388	39,699,431	40,507,640
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	30,587,330	3,770,660	3,562,780	3,770,660	2,729,500	2,727,710	2,729,500	1,327,860	1,327,860	1,281,600	2,548,980	2,326,920	2,483,300
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	30,587,330	3,770,660	3,562,780	3,770,660	2,729,500	2,727,710	2,729,500	1,327,860	1,327,860	1,281,600	2,548,980	2,326,920	2,483,300

System Balancing Purchases													
COB	13,201,099	457,257	1,519,552	903,825	1,057,960	712,828	1,888,286	2,222,511	1,965,725	1,674,691	72,355	274,032	452,079
Four Corners	33,298,752	2,379,926	3,256,568	6,445,609	5,557,763	3,300,857	1,041,200	3,074,581	1,752,674	1,291,456	1,878,652	2,077,183	1,242,283
Mead	5,236,996	54,987	209,238	148,319	461,328	321,239	630,359	778,342	877,006	976,508	248,236	381,754	149,681
Mid Columbia	85,573,262	2,316,856	2,042,950	1,217,074	3,524,212	10,979,241	5,389,806	25,334,552	21,754,243	8,144,198	2,164,368	1,022,045	1,683,717
Mona	11,878,467	714,689	866,379	1,787,210	1,412,169	371,382	605,963	1,077,025	849,829	976,667	1,127,177	869,730	1,220,246
NOB	11,123,358	1,764	832,045	305,188	1,001,201	460,104	118,948	4,123,466	3,026,488	1,254,154	-	-	-
Palo Verde	33,078,338	4,853,684	5,185,279	4,939,266	2,770,597	4,206,806	3,083,124	2,779,097	829,112	1,530,655	1,074,124	768,827	1,057,767
EIM Imports/Exports	(36,991,033)	(2,454,630)	(2,054,694)	(4,101,599)	(3,852,740)	(3,990,343)	(1,934,457)	(5,026,190)	(4,565,020)	(3,134,712)	(1,866,324)	(1,863,949)	(2,146,375)
Emergency Purchases	1,101,364	1,001	71,713	373,864	304,702	-	6,973	9,063	2,803	330,672	-	293	281
Total System Balancing Purchases	157,500,602	8,325,535	11,929,029	12,018,754	12,237,192	16,362,114	10,830,202	34,372,447	26,492,861	13,044,289	4,698,588	3,529,914	3,659,678
Total Purchased Power & Net Inter	702,607,551	54,097,331	56,529,344	60,682,876	60,045,746	63,618,614	58,421,594	81,427,729	72,139,066	55,365,414	47,172,956	46,006,265	47,100,618
Wheeling & U. of F. Expense													
Firm Wheeling	130,829,566	11,311,836	11,248,707	11,034,734	11,075,440	10,156,885	11,021,387	10,793,423	10,561,834	10,625,959	10,750,813	10,945,089	11,303,456
C&T EIM Admin fee	1,857,444	143,950	147,442	179,201	193,210	220,555	188,965	118,803	123,981	132,890	139,034	135,191	134,221
ST Firm & Non-Firm	114,874	16,497	4,535	-	1,368	3,682	5,969	17,630	19,801	17,269	9,069	8,974	10,082
Total Wheeling & U. of F. Expense	132,801,884	11,472,283	11,400,684	11,213,936	11,270,018	10,381,122	11,216,320	10,929,856	10,705,616	10,776,119	10,898,916	11,089,255	11,447,759
Coal Fuel Burn Expense													
Cholla	27,072,484	2,729,201	1,899,617	-	-	1,731,730	2,964,749	3,740,660	3,896,070	2,508,361	2,112,294	2,789,423	2,700,380
Colstrip	15,384,303	1,370,043	1,234,730	1,333,299	1,207,896	803,103	1,316,320	1,386,100	1,325,070	1,311,707	1,372,519	1,371,874	1,351,643
Craig	24,926,067	2,316,879	1,551,680	1,821,944	1,748,323	2,120,732	2,323,106	2,295,204	2,411,303	1,674,307	2,138,740	2,157,185	2,366,665
Dave Johnston	61,116,023	4,935,110	4,707,489	4,706,446	4,463,615	5,084,248	5,103,003	5,266,356	5,839,056	5,356,979	5,327,064	5,251,854	5,074,803
Hayden	11,740,956	1,025,326	1,093,144	480,487	659,860	911,402	978,245	1,278,366	1,247,266	1,264,444	960,755	791,496	1,050,164
Hunter	101,433,034	12,810,792	8,483,724	4,276,485	3,613,387	4,635,494	8,071,233	12,358,221	11,815,480	10,825,000	7,653,341	6,700,783	10,189,094
Huntington	105,273,013	11,902,311	9,080,898	8,008,833	6,257,584	6,066,252	8,325,833	12,476,468	11,289,048	8,387,405	5,745,820	7,265,217	10,467,344
Jim Bridger	215,631,825	21,914,588	19,839,469	17,940,242	13,578,669	13,206,582	15,334,595	21,603,564	20,085,647	15,415,082	15,421,955	19,768,265	21,523,165
Naughton	81,168,515	7,089,007	6,772,940	6,834,386	6,424,557	5,085,670	6,385,974	7,210,731	7,408,808	6,642,654	6,990,360	6,929,062	7,394,365
Wyodak	26,072,774	1,975,111	1,862,039	1,577,407	1,471,345	2,457,876	2,425,519	2,737,171	2,824,118	2,216,388	2,523,687	1,964,551	2,037,561
Total Coal Fuel Burn Expense	669,818,994	68,068,368	56,525,730	46,979,529	39,425,236	42,103,089	53,228,577	70,352,842	68,141,866	55,602,326	50,246,536	54,989,710	64,155,185
Gas Fuel Burn Expense													
Chehalis	45,631,420	4,953,273	4,129,290	3,564,981	2,671,041	1,434,411	2,403,155	3,699,085	4,851,554	4,765,681	4,572,082	4,252,850	4,334,016
Currant Creek	55,027,793	6,151,208	3,801,782	3,796,676	2,995,774	4,094,344	4,162,683	4,958,857	4,771,240	4,828,310	4,774,012	4,763,181	5,929,728
Gadsby	4,359,416	183,671	183,121	152,974	145,856	210,646	465,882	968,222	937,434	708,737	253,031	37,760	112,081
Gadsby CT	2,497,491	148,930	93,901	121,327	76,454	129,520	197,809	536,870	502,503	419,997	99,019	42,169	128,990
Hermiston	21,874,381	2,438,280	1,934,366	2,142,731	1,390,832	304,653	1,627,734	1,508,121	1,878,583	1,968,809	2,012,150	2,158,318	2,509,804
Lake Side 1	63,111,308	5,769,540	5,570,116	5,606,640	3,659,513	3,530,263	4,834,282	5,649,326	5,749,699	5,418,782	5,318,212	5,497,807	6,507,126
Lake Side 2	64,534,242	4,894,786	4,488,428	5,056,539	4,630,799	4,717,509	5,093,851	6,159,149	6,188,709	5,952,459	5,753,335	5,407,822	6,190,857
Total Gas Fuel Burn	257,036,050	24,539,689	20,201,004	20,441,868	15,570,269	14,421,346	18,785,396	23,479,630	24,879,723	24,062,774	22,781,841	22,159,907	25,712,603
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	18,213,555	595,355	954,970	2,055,920	1,594,875	1,811,485	1,659,000	1,605,025	1,567,825	1,636,500	1,776,455	1,609,350	1,346,795
Clay Basin Gas Storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	33,969,972	2,852,521	2,769,818	2,852,653	2,796,566	2,842,980	2,813,331	2,876,893	2,876,972	2,827,995	2,841,546	2,784,527	2,834,170
Total Gas Fuel Burn Expense	309,219,577	27,987,565	23,925,792	25,350,441	19,961,710	19,075,812	23,257,728	27,961,549	29,324,520	28,527,269	27,399,842	26,553,783	29,893,567
Other Generation													
Blundell	4,676,489	420,164	379,337	390,099	334,480	382,059	368,962	393,286	395,628	376,077	396,646	412,279	427,471
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	7,455,847	655,459	596,413	619,860	587,134	603,459	624,025	683,380	654,297	582,466	583,838	605,279	660,236
Total Other Generation	12,132,336	1,075,623	975,749	1,009,959	921,614	985,519	992,987	1,076,666	1,049,924	958,543	980,485	1,017,559	1,087,708
Net Power Cost	**1,479,821,158**	130,194,001	121,486,364	120,688,327	112,081,843	114,952,614	123,934,745	151,080,304	134,480,163	116,387,211	112,159,877	114,989,176	127,386,533

Docket No. UE 356
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

April 2019

PacifiCorp
CY 2020 TAM
Other Revenues - Stand Alone TAM Adjustment
Initial Filing

		Total Company					Oregon Allocated	
Line no		UE-339 Final	CY 2020 Initial	Factor	Factors CY 2019	Factors CY 2020	UE-339 Final	CY 2020 Initial
1	Seattle City Light - Stateline Wind Farm	(11,086,374)	(11,302,961)	SG	26.725%	26.456%	(2,962,812)	(2,990,294)
2	Non-company owned Foote Creek	(884,834)	(691,961)	SG	26.725%	26.456%	(236,470)	(183,064)
3	BPA South Idaho Exchange	-	-	SG	26.725%	26.456%	-	-
4	Little Mountain Steam Revenues	-	-	SG	26.725%	26.456%	-	-
5	James River Royalty Offset	-	-	SG	26.725%	26.456%	-	-
6								
7	Total Other Revenue	(11,971,208)	(11,994,922)				(3,199,282)	(3,173,358)
8								
9	Decrease (Increase) in Other Revenues Absent Load Change							25,924
10								
11	Baseline Other Revenues in Rates						(3,199,282)	
12	$ Change due to load variance from UE 339 CY 2019 forecast						(42,021)	
13	Other Revenues in Rates using 2020 load forecast						(3,241,304)	
14								
15	**Decrease (Increase) in Other Revenues Including Load Change**							**67,946**

REDACTED
Docket No. UE 356
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

April 2019

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

Docket No. UE 356
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

April 2019

PacifiCorp
Oregon 2020 TAM
EIM Costs
Initial Filing

$ dollars

	CY 2020 EIM Costs 13 Month Average					
	Total Company		Factor	Factors	Oregon Allocated	
	2019 Final	Initial Filing		CY 2020	2019 Final	Initial Filing
Capital Investment	16,437,307	16,437,307	SG	26.456%	4,392,839	4,348,628
ADIT	(1,853,075)	(1,225,243)	SG	26.456%	(495,231)	(324,148)
Depreciation Reserve	(11,426,214)	(12,019,754)	SG	26.456%	(3,053,634)	(3,179,927)
Net Rate Base	3,158,017	3,192,309			843,974	844,552
	9.30%	9.30%			9.30%	9.30%
Pre-Tax Return on Rate Base	$ 293,558	$ 296,746	SG	26.456%	$ 78,453	$ 78,507
Operation & Maintenance (Ongoing)	1,300,577	997,976	SG	26.456%	347,577	264,023
Depreciation	1,485,613	277,314	SG	26.456%	397,027	73,366
Total Revenue Requirement	$ 3,079,748	$ 1,572,036			$ 823,057	$ 415,895
CAISO Fee in net power costs	$ 1,429,782	$ 1,857,444	SG	26.456%	382,107	491,403
Total EIM Costs	$ 4,509,530	$ 3,429,480			$ 1,205,163	$ 907,298

Docket No. UE 356
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

April 2019

PacifiCorp
CY 2020 TAM
Production Tax Credits

Line no	Plant Name	PTC Expiration Date	Total Company CY 2019 Final	Factor	Factors CY 2019	Oregon Allocated CY 2019 Final	Oregon Allocated Revenue Requirement
	PTC Revenue Requirement in UE-339						
1	JC Boyle	11/7/2015	$ -	SG	26.725%	$ -	$ -
2	Blundell Bottoming Cycle	12/1/2017	-	SG	26.725%	-	-
3	Glenrock	12/30/2018	(2,677,520)	SG	26.725%	(715,562)	(948,853)
4	Glenrock III	1/16/2019	(172,547)	SG	26.725%	(46,113)	(61,147)
5	Goodnoe	12/17/2017	(400,326)	SG	26.725%	(106,986)	(141,867)
6	High Plains Wind	10/14/2019	(6,821,943)	SG	26.725%	(1,823,151)	(2,417,543)
7	Leaning Juniper 1	9/13/2016	(1,533,630)	SG	26.725%	(409,860)	(543,484)
8	Leaning Juniper Indemnity	9/13/2016	(19,937)	SG	26.725%	(5,328)	(7,065)
9	Marengo	8/2/2017	(1,055,916)	SG	26.725%	(282,192)	(374,193)
10	Marengo II	6/25/2018	(441,520)	SG	26.725%	(117,995)	(156,465)
11	McFadden Ridge	10/31/2019	(2,102,460)	SG	26.725%	(561,878)	(745,064)
12	Seven Mile	12/30/2018	(3,098,241)	SG	26.725%	(827,999)	(1,097,947)
13	Seven Mile II	12/30/2018	(649,037)	SG	26.725%	(173,454)	(230,004)
14	Dunlap I Wind	9/29/2020	(9,281,107)	SG	26.725%	(2,480,358)	(3,289,015)
15							
16	Total Production Tax Credit		$ (28,254,184)			$ (7,550,876)	$ (10,012,645)
17							
18							
19							
20							

Line no	Plant Name	PTC Expiration Date	Repowering In-Service Date	Total Company CY 2020 Initial	Factor	Factors CY 2020	Oregon Allc CY 2020 Initial
21	**PTC Revenue Requirement CY 2020**						
22							
23	Plant Name	PTC Expiration Date	Repowering In-Service Date	Initial	Factor	Factors CY 2020	Initial
24	JC Boyle	11/7/2015		-	SG	26.456%	-
25	Blundell Bottoming Cycle	12/1/2017		-	SG	26.456%	-
26	Glenrock	12/30/2018	10/1/2019	(9,418,089)	SG	26.456%	(2,491,635)
27	Glenrock III	1/16/2019	8/1/2020	(1,512,384)	SG	26.456%	(400,114)
28	Goodnoe	12/17/2017	10/1/2019	(7,124,587)	SG	26.456%	(1,884,870)
29	High Plains Wind	10/14/2019	11/1/2019	(9,619,262)	SG	26.456%	(2,544,857)
30	Leaning Juniper 1	9/13/2016	10/1/2019	(7,433,361)	SG	26.456%	(1,966,558)
31	Leaning Juniper Indemnity	9/13/2016	10/1/2019	(96,634)	SG	26.456%	(25,565)
32	Marengo	8/2/2017	11/1/2019	(11,961,344)	SG	26.456%	(3,164,475)
33	Marengo II	6/25/2018	11/1/2019	(5,839,670)	SG	26.456%	(1,544,934)
34	McFadden Ridge	10/31/2019	11/1/2019	(2,934,519)	SG	26.456%	(776,352)
35	Rolling Hills	1/16/2019	10/1/2019	-	SG	26.456%	-
36	Seven Mile	12/30/2018	7/1/2019	(10,580,606)	SG	26.456%	(2,799,189)
37	Seven Mile II	12/30/2018	7/1/2019	(2,205,151)	SG	26.456%	(583,391)
38	Dunlap I Wind	9/29/2020	1/1/2021	(6,464,915)	SG	26.456%	(1,710,348)
39							
40	Total Production Tax Credit			(75,190,522)			(19,892,288)
41							
42							Increase Absent Load Change
43							
44							

PacifiCorp
CY 2020 TAM
Calculation of Production Tax Credits - Stand Alone TAM Adjustment

		Total Company					
		Generation (KWh)		Tax Rate		Tax Credit	
Line no		CY 2019	CY 2020	CY 2019	CY 2020	CY 2019	CY 2020
1	JC Boyle	-	-	$ 0.012	$ 0.012	$ -	$ -
2	Blundell Bottoming Cycle	-	-	$ 0.025	$ 0.025	$ -	$ -
3	Glenrock	107,100,799	376,723,569	$ 0.025	$ 0.025	$ 2,677,520	$ 9,418,089
4	Glenrock III	6,901,887	60,495,340	$ 0.025	$ 0.025	$ 172,547	$ 1,512,384
5	Goodnoe	16,013,036	284,983,483	$ 0.025	$ 0.025	$ 400,326	$ 7,124,587
6	High Plains Wind	272,877,713	384,770,478	$ 0.025	$ 0.025	$ 6,821,943	$ 9,619,262
7	Leaning Juniper 1	61,345,191	297,334,429	$ 0.025	$ 0.025	$ 1,533,630	$ 7,433,361
8	Leaning Juniper Indemnity	797,487	3,865,348	$ 0.025	$ 0.025	$ 19,937	$ 96,634
9	Marengo	42,236,642	478,453,771	$ 0.025	$ 0.025	$ 1,055,916	$ 11,961,344
10	Marengo II	17,660,802	233,586,796	$ 0.025	$ 0.025	$ 441,520	$ 5,839,670
11	McFadden Ridge	84,098,410	117,380,750	$ 0.025	$ 0.025	$ 2,102,460	$ 2,934,519
12	Rolling Hills	-	-	$ 0.025	$ 0.025	$ -	$ -
13	Seven Mile	123,929,642	423,224,241	$ 0.025	$ 0.025	$ 3,098,241	$ 10,580,606
14	Seven Mile II	25,961,483	88,206,059	$ 0.025	$ 0.025	$ 649,037	$ 2,205,151
15	Dunlap I Wind	371,244,280	258,596,617	$ 0.025	$ 0.025	$ 9,281,107	$ 6,464,915
16	Total Production Tax Credit					$ 28,254,184	$ 75,190,522

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 356
Exhibit PAC/107
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Step Log Change

April 2019

2020 TAM Step Log

ORTAM19			$ 1,452,088,256
	Description	**Detail**	**Impact**
	Routine Updates		22,989,841
Step 1	Scalar for Price Curve	Apply 12-month rolling CAISO day-ahead hourly prices	4,707,509
Step 2	Solar Hourly Shape	Apply 2017 actual solary generation	916,057
Step 3	Thermal Attributes updates	**Minimum Operationa Level Change:** Dave Johnson 3: 140MW May - Oct, 170MW Nov -Apr (was 120MW) Hunter 1: 79.7MW (was 121.9MW) Hunter 2: 51.3MW (was 78.4MW) Hunter 3: 72MW (was 150MW) Huntington 1: 80MW (was 100MW) Huntington 2: 80MM (was 100MW) Jim Bridger 2: 53MW (was 80MW) Naughton 1: 21MW (was 30MW) Naughton 2: 28MW (was 50MW)	843,739
Step 4	QF Contract Delay Rate (CDR)	CDR for QFs coming online after 2019	(216,024)
Step 5	Split Wyoming Northeast to Wyoming East and Wyoming North		(17,009)
Step 6	Coal Plant Economic Cycling		(1,491,211)
ORTAM20			$ 1,479,821,158

Docket No. UE 356
Exhibit PAC/108
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

March 1 Notice Letter

April 2019

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2019

VIA ELECTRONIC MAIL

Attn: Parties to docket UE 339

RE: 2020 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 2020 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 2020 TAM, the company is treating the 2020 TAM as a stand-alone filing for purposes of the methodology change notice requirement.

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

- The scalars applied to the official forward price curve are updated to be consistent with the methodology used in the 2017 integrated resource plan update.
- Solar generation will be shaped hourly according to the 2017 actual generation.
- The transmission topology will be updated to split the Wyoming Northeast bubble into Wyoming East and Wyoming North bubbles.
- Energy imbalance market (EIM) benefits will be forecasted using a regression analysis based on electric and natural gas market prices, EIM transfer capability, and spring over supply conditions.

PacifiCorp will include an exhibit to testimony in the direct filing identifying all changes as outlined above.

Additionally, the Glenrock III repowering project will come online in 2020 and PacifiCorp will propose that the benefits be included in the TAM and the costs will be included in a renewable adjustment clause (RAC) that will be effective concurrently with the online date consistent with the treatment of the 2019 repowering in 2019 TAM stipulation.

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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 No. UE-207, Order No. 09-432, Appendix A at 4-5 (Oct. 30, 2009).

Please direct any questions regarding this notice to Cathie Allen, regulatory affairs manager at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

cc: UE 339 Service List

Docket No. UE 356
Exhibit PAC/109
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 2017

April 2019

PacifiCorp

NPC Backcast 2017 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	13,255,094	1,219,639	919,396	936,347	940,782	966,575	1,012,652	1,265,779	1,279,305	1,137,228	1,161,214	1,182,114	1,234,063
BPA Wind	2,320,372	262,566	288,013	227,915	256,709	(50,956)	103,515	62,530	106,341	120,347	264,060	309,264	370,069
Hurricane Sale	15,205	1,300	1,170	1,170	1,300	1,365	1,495	1,625	1,560	1,084	1,067	1,033	1,037
Leaning Juniper Revenue	74,053	5,703	3,911	4,580	2,775	4,498	3,512	10,851	12,685	7,956	6,956	5,014	5,611
UMPA II s45631	3,482,947	593,573	486,581	463,391	489,001	546,001	904,399	-	-	-	-	-	-
Total Long Term Firm Sales	19,147,671	2,082,780	1,699,072	1,633,403	1,690,567	1,467,483	2,025,572	1,340,785	1,399,891	1,266,615	1,433,297	1,497,425	1,610,779
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	6,181,308	727,300	661,248	733,404	616,840	637,868	619,640	-	-	-	737,436	713,160	734,412
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	2,622,460	885,790	821,160	915,510	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	132,588,170	27,576,140	23,558,880	26,198,520	8,871,100	9,204,770	9,098,900	4,584,500	4,951,260	4,584,500	4,667,880	4,532,100	4,759,620
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	141,391,938	29,189,230	25,041,288	27,847,434	9,487,940	9,842,638	9,718,540	4,584,500	4,951,260	4,584,500	5,405,316	5,245,260	5,494,032
System Balancing Sales													
COB	30,075,973	2,686,911	3,005,691	2,804,872	2,388,620	1,540,924	1,217,101	2,335,317	2,909,595	4,137,741	2,411,322	2,234,166	2,403,713
Four Corners	76,768,113	5,918,975	3,132,224	5,323,839	6,305,300	4,804,918	5,640,650	7,578,065	8,875,955	9,461,949	6,893,189	5,890,730	6,942,319
Mead	26,931,847	2,296,100	1,293,691	1,241,819	1,146,257	1,547,764	1,515,414	2,955,579	3,111,982	3,412,345	2,637,025	2,626,651	3,147,220
Mid Columbia	42,558,454	6,075,440	4,141,199	2,865,903	1,586,906	1,891,460	904,365	4,953,503	6,800,936	4,298,910	2,740,010	3,248,281	3,051,540
Mona	23,112,165	2,205,678	1,424,769	1,316,783	933,491	2,010,967	1,047,056	1,195,940	2,001,932	3,719,342	1,695,579	2,842,254	2,718,374
NOB	5,730,455	1,006,632	364,098	344,042	328,861	444,903	634,131	899,258	1,087,386	422,481	85,006	51,180	62,475
Palo Verde	45,347,641	1,245,166	945,920	1,087,261	1,984,966	2,555,654	2,715,959	6,255,492	5,150,889	6,389,947	5,687,675	5,312,957	6,015,756
EIM Exports	12,158,730	924,918	732,369	686,851	687,839	888,430	1,411,800	1,462,121	1,445,738	1,215,342	874,514	870,520	958,287
Trapped Energy	14,463	4,453	-	3,041	1,463	-	4,324	-	-	-	-	603	579
Total System Balancing Sales	262,697,841	22,364,273	15,039,961	15,674,411	15,363,704	15,685,020	15,090,800	27,635,276	31,384,414	33,058,057	23,024,320	23,077,342	25,300,263
Total Special Sales For Resale	423,237,450	53,636,283	41,780,321	45,155,248	26,542,211	26,995,142	26,834,912	33,560,561	37,735,565	38,909,172	29,862,934	29,820,027	32,405,074

PacifiCorp

NPC Backcast 2017 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	2,527,428	159,688	165,512	443,045	388,052	272,675	167,730	303,119	254,850	137,624	130,538	50,501	54,096
Combine Hills Wind	4,421,951	124,089	336,346	370,394	568,819	324,364	440,544	395,253	283,035	307,465	540,139	519,743	211,760
Deseret Purchase	31,033,535	2,632,813	2,338,106	2,458,035	2,356,016	2,405,906	2,336,460	2,986,891	2,969,837	2,555,663	2,670,521	2,561,370	2,761,916
Douglas PUD Settlement	1,930,879	53,410	135,596	260,683	339,332	343,832	351,161	171,880	91,101	98,420	21,208	48,325	15,931
Eagle Mountain - UAMPS/UMPA	3,879,963	229,068	192,563	188,205	328,088	429,825	640,570	504,722	492,416	273,464	174,394	173,292	253,356
Gemstate	1,656,195	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	132,628	155,887	132,628
Hurricane Purchase	142,820	14,040	14,918	10,355	8,600	7,254	7,196	11,759	14,859	13,426	9,842	7,047	23,528
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	6,804,970	569,420	553,380	573,430	573,430	573,430	565,410	561,400	561,400	557,390	573,430	573,430	569,420
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
P4 Production	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	148,196	13,127	3,795	13,127	13,127	13,127	13,127	13,127	13,127	13,127	13,127	13,127	13,127
Rock River Wind	5,237,668	534,361	569,051	534,421	431,744	231,465	303,122	117,891	197,691	243,144	554,794	657,074	862,909
Small Purchases east	37,149	3,476	3,298	3,153	3,007	2,886	2,977	3,180	3,194	3,184	2,707	3,026	3,063
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	19,879,429	2,375,811	2,465,504	2,210,980	1,560,950	872,870	1,227,703	676,408	635,249	947,078	2,176,695	2,310,724	2,419,456
Top of the World Wind	40,574,156	4,670,308	5,071,329	4,397,323	3,167,640	2,163,140	2,496,003	1,353,546	1,321,129	1,884,840	4,632,665	4,277,051	5,139,181
Tri-State Purchase	9,580,966	818,255	757,174	832,524	822,101	790,257	757,460	876,794	851,147	767,661	766,803	775,448	765,341
Wolverine Creek Wind	10,197,944	777,729	1,416,105	1,359,912	1,125,565	613,520	813,492	452,138	515,510	546,850	844,139	1,238,023	494,961
West Valley Toll	4,464,448	-	-	-	-	-	-	720,437	1,028,442	846,381	805,022	561,306	502,860
Long Term Firm Purchases Total	169,647,496	15,373,639	16,420,722	16,053,631	14,084,515	11,442,596	12,520,999	11,546,591	11,631,033	11,593,763	16,309,469	16,186,189	16,484,350
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities													
QF California	8,339,871	874,271	932,682	1,075,765	1,183,644	1,204,113	778,740	430,845	309,652	418,866	336,030	404,535	390,727
QF Idaho	8,981,370	499,655	519,484	752,911	800,620	895,577	915,594	874,206	784,753	736,488	708,189	767,076	726,817
QF Oregon	29,959,703	1,799,068	2,245,572	3,003,767	3,429,133	3,459,307	2,692,415	2,517,685	2,317,096	2,249,079	2,073,802	2,103,023	2,069,755
QF Utah	8,961,808	571,371	645,874	815,496	878,734	911,911	851,226	750,752	765,303	738,763	699,019	680,267	653,091
QF Washington	231,757	-	0	-	186	21,646	52,083	64,483	60,166	28,390	4,802	-	-
QF Wyoming	232,794	21,715	19,894	15,037	13,243	10,919	10,415	9,078	18,084	10,274	32,447	29,215	42,474
Biomass One QF	11,397,185	486,271	1,116,787	1,126,716	468,977	887,693	896,901	895,150	1,117,828	1,103,216	1,343,134	1,225,000	729,513
Chevron Wind QF	543,867	49,323	96,267	80,220	34,699	22,653	29,638	18,109	22,976	16,613	47,759	53,304	72,306
DCFP QF	130,033	3,559	4,795	3,582	3,975	6,475	4,490	11,070	27,333	30,607	17,382	7,890	8,875
Chopin Wind QF	1,342,188	55,603	111,784	138,423	172,528	101,921	129,437	107,356	84,775	77,216	161,998	146,588	54,559
Enterprise Solar I QF	12,193,357	516,908	643,415	949,758	1,059,247	1,259,683	1,331,237	1,431,960	1,480,382	1,101,284	1,047,460	707,958	664,066
Escalante Solar I QF	11,009,364	452,887	591,941	826,930	982,582	1,182,109	1,345,998	1,285,776	1,275,511	1,002,132	952,434	602,588	508,474
Escalante Solar II QF	10,593,355	435,584	562,744	782,740	932,824	1,125,736	1,281,851	1,232,893	1,223,180	993,362	877,835	598,786	545,821
Escalante Solar III QF	10,144,059	416,338	553,227	752,403	912,865	1,082,241	1,280,762	1,202,938	1,146,017	935,788	821,652	545,791	494,036
Evergreen BioPower QF	3,796,778	255,647	241,281	251,645	300,350	313,234	358,593	369,175	416,371	345,135	360,181	269,945	315,222
ExxonMobil QF	73,970	27,213	-	-	-	-	-	-	-	35,026	11,731	-	-
Five Pine Wind QF	7,899,497	535,886	1,084,122	905,346	746,095	371,693	475,842	396,154	436,981	466,525	825,414	906,027	749,413
Foote Creek III Wind QF	1,339,665	125,236	149,212	120,025	126,865	58,911	76,269	41,546	81,242	78,456	144,473	164,025	173,404
Granite Mountain East Solar QF	10,757,765	457,586	578,687	894,281	979,691	1,160,730	1,353,550	1,241,011	1,188,105	894,919	878,497	568,120	562,587
Granite Mountain West Solar QF	6,924,543	290,276	377,461	555,450	656,258	767,124	891,494	811,581	701,299	563,837	572,823	375,238	361,702
Iron Springs Solar QF	11,307,401	464,009	615,908	938,963	1,009,817	1,197,354	1,420,937	1,293,748	1,316,200	933,593	906,388	621,945	588,540
Kennecott Refinery QF	154,562	-	-	24,603	14,795	22,068	19,129	21,251	18,079	7,532	-	10,869	16,236
Kennecott Smelter QF	830,300	29,586	75,490	78,406	34,289	72,438	78,524	167,980	128,062	66,700	-	42,947	55,879
Latigo Wind Park QF	9,297,439	858,849	617,886	824,343	971,723	744,762	762,616	553,153	449,611	717,694	987,169	963,542	846,091
Mountain Wind 1 QF	9,098,223	1,014,961	1,007,126	968,751	711,712	454,125	560,724	247,524	389,952	441,761	885,268	925,053	1,491,266
Mountain Wind 2 QF	13,790,567	1,525,686	1,521,354	1,523,218	1,065,101	675,540	990,758	431,473	649,483	709,125	1,255,073	1,350,918	2,092,838
North Point Wind QF	17,372,915	981,630	2,323,175	1,990,287	1,667,316	827,010	1,085,694	946,673	1,108,538	1,080,760	1,881,642	1,940,295	1,539,895
Oregon Wind Farm QF	10,255,889	128,433	616,194	892,110	1,265,862	887,969	1,087,349	1,369,860	899,366	778,956	1,035,084	856,768	437,938
Pavant II Solar QF	3,051,436	104,699	141,745	237,884	299,297	328,597	351,567	371,271	384,977	272,237	271,351	145,630	142,180
Pioneer Wind Park I QF	10,786,228	1,265,371	1,145,131	1,111,913	946,936	519,696	657,335	416,765	409,396	435,725	1,179,709	1,324,256	1,373,996
Power County North Wind QF	4,643,988	344,808	505,465	412,813	472,710	271,545	325,916	185,114	340,899	250,112	515,381	452,969	566,256
Power County South Wind QF	4,198,290	301,062	504,614	402,978	464,803	234,860	274,764	140,085	276,032	199,555	439,002	437,859	522,676
Roseburg Dillard QF	505,832	30,462	15,428	28,665	77,155	65,850	64,877	59,613	57,590	21,360	36,102	32,779	15,950

PacifiCorp

NPC Backcast 2017 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Spanish Fork Wind 2 QF	2,621,025	200,323	154,150	196,241	129,672	156,900	197,349	318,046	322,741	240,404	227,949	245,798	231,451
Sunnyside QF	28,795,263	2,577,607	2,440,467	2,294,688	1,295,812	2,618,945	2,557,590	2,552,516	2,570,521	2,543,478	2,147,771	2,587,601	2,608,268
Tesoro QF	166,954	12,998	14,687	12,607	16,362	13,549	6,875	13,056	1,121	7,375	14,885	9,609	43,829
Threemile Canyon Wind QF	1,439,602	52,340	70,532	125,455	196,533	131,846	184,488	194,669	112,732	104,233	126,818	88,478	51,478
Three Peaks Solar QF	9,342,072	371,893	491,364	805,870	911,193	1,019,832	1,096,204	989,872	970,470	811,417	826,487	567,189	480,280
Utah Pavant Solar QF	3,843,525	136,335	170,360	280,942	324,830	406,306	475,263	488,042	481,932	336,825	349,022	206,617	187,051
Utah Red Hills Solar QF	12,174,980	395,463	588,029	957,416	1,047,531	1,280,032	1,406,303	1,438,132	1,501,091	1,318,752	985,332	695,121	561,781
Qualifying Facilities Total	298,529,421	18,670,913	23,494,334	27,158,650	26,605,966	26,772,899	28,360,795	25,890,607	25,845,845	23,103,569	25,987,498	23,661,620	22,976,724
Mid-Columbia Contracts													
Douglas - Wells	3,747,423	310,219	310,219	310,219	310,219	310,219	310,219	310,219	310,219	316,418	316,418	316,418	316,418
Grant Reasonable	(79,584)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)	(6,632)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	1,982,072	165,173	165,173	165,173	165,173	165,173	165,173	165,173	165,173	165,173	165,173	165,173	165,173
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	5,649,911	468,760	468,760	468,760	468,760	468,760	468,760	468,760	468,760	474,959	474,959	474,959	474,959
Total Long Term Firm Purchases	473,826,829	34,513,312	40,383,816	43,681,041	41,159,241	38,684,255	41,350,553	37,905,957	37,945,638	35,172,291	42,771,925	40,322,767	39,936,032
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	36,275,380	6,857,870	6,199,320	5,242,050	3,048,000	-	-	3,957,500	4,274,100	3,957,500	937,040	901,000	901,000
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	11,395,755	3,997,425	3,093,620	4,304,710	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	47,671,135	10,855,295	9,292,940	9,546,760	3,048,000	-	-	3,957,500	4,274,100	3,957,500	937,040	901,000	901,000

PacifiCorp

NPC Backcast 2017 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
System Balancing Purchases													
COB	17,556,513	2,362,407	1,257,306	910,038	886,902	562,071	1,222,932	2,712,213	2,864,670	1,474,108	966,303	990,370	1,347,193
Four Corners	28,992,895	1,343,352	2,007,401	2,501,919	2,162,901	2,097,766	1,907,845	3,155,032	6,047,534	2,831,961	1,552,796	2,441,896	942,491
Mead	7,570,541	834,970	578,995	639,954	601,071	715,574	623,893	916,067	1,083,463	358,810	360,572	435,921	421,250
Mid Columbia	122,150,442	14,453,391	9,385,830	6,901,290	5,478,729	9,562,706	9,706,828	21,269,165	16,435,623	8,958,167	3,609,499	6,971,098	9,418,117
Mona	20,145,676	1,470,968	1,498,341	2,100,306	2,397,853	2,494,916	2,526,663	2,022,197	1,423,727	1,371,975	642,155	1,332,294	864,281
NOB	12,117,419	2,502,581	656,167	634,753	589,129	817,285	1,187,006	1,826,693	2,491,378	910,046	187,481	117,807	197,094
Palo Verde	71,765,327	18,078,943	11,894,301	12,677,685	5,032,497	5,995,209	6,214,950	2,434,470	2,866,190	1,749,011	1,510,503	1,623,630	1,687,937
EIM Imports	(4,750,725)	(532,167)	(532,167)	(532,167)	(532,167)	(532,167)	(123,348)	(123,348)	(123,348)	(123,348)	(532,167)	(532,167)	(532,167)
Emergency Purchases	108,575	1,147	5,930	-	11,326	7,247	-	62,794	19,388	-	743	-	-
Total System Balancing Purchases	275,656,664	40,515,593	26,752,103	25,833,780	16,628,240	21,720,607	23,266,770	34,275,283	33,108,624	17,530,731	8,297,886	13,380,849	14,346,197
Total Purchased Power & Net Inter	802,554,627	86,334,199	76,878,860	79,511,580	61,285,481	60,854,862	65,067,323	76,588,740	75,778,363	57,110,522	52,456,851	55,054,617	55,633,229
Wheeling & U. of F. Expense													
Firm Wheeling	144,232,139	11,627,114	11,842,313	12,119,407	11,470,653	11,194,729	12,116,632	12,553,679	11,210,330	11,426,439	12,856,065	13,479,297	12,335,480
C&T EIM Admin fee	1,318,331	109,729	109,650	109,730	109,980	110,100	110,119	109,861	109,861	109,861	109,861	109,761	109,818
ST Firm & Non-Firm	18,328	2,635	1,487	1,370	-	3,237	375	425	5,446	1,028	176	1,153	995
Total Wheeling & U. of F. Expense	145,568,798	11,739,478	11,953,450	12,230,508	11,580,633	11,308,066	12,227,126	12,663,965	11,325,637	11,537,328	12,966,102	13,590,212	12,446,293
Coal Fuel Burn Expense													
Cholla	49,800,092	4,947,914	3,087,350	3,412,877	3,868,844	3,962,657	4,308,689	5,206,815	4,807,995	4,654,351	4,034,541	4,058,263	3,449,797
Colstrip	14,347,237	1,470,101	1,237,473	1,060,599	926,660	680,437	746,387	866,027	1,501,332	1,463,178	1,514,139	1,400,792	1,480,113
Craig	26,222,318	2,506,251	2,093,419	2,115,453	1,242,547	1,702,893	2,443,120	1,911,296	2,475,661	2,436,297	2,465,691	2,275,440	2,554,250
Dave Johnston	55,974,330	4,779,262	4,125,373	3,714,113	3,650,635	5,040,845	4,950,703	5,017,620	5,312,098	5,106,998	5,098,495	4,613,488	4,564,700
Hayden	11,852,293	1,031,696	785,766	950,399	1,073,860	1,102,009	1,011,903	1,266,027	1,259,376	999,846	642,594	877,907	850,909
Hunter	155,684,772	13,561,782	11,038,180	11,670,976	12,623,656	12,061,175	12,743,693	14,199,932	13,826,341	12,850,449	13,863,995	13,127,808	14,116,785
Huntington	113,571,825	11,965,821	6,521,369	7,609,695	7,492,850	9,306,181	8,665,550	10,359,545	11,039,282	10,356,195	9,758,246	9,990,796	10,506,295
Jim Bridger	197,207,582	23,370,389	13,012,909	11,394,981	9,776,408	11,054,678	15,397,370	21,090,166	22,362,778	19,561,254	16,337,642	17,018,394	16,830,615
Naughton	98,606,510	9,825,655	6,901,761	7,762,045	6,404,069	7,787,943	8,138,451	9,147,803	8,736,700	8,624,093	8,150,375	8,479,517	8,648,097
Wyodak	28,326,883	2,001,917	1,734,792	2,412,363	2,352,596	2,609,888	2,464,725	2,786,466	2,427,951	2,579,407	2,565,534	2,160,656	2,230,587
Total Coal Fuel Burn Expense	751,593,842	75,460,787	50,538,389	52,103,501	49,412,124	55,308,706	60,870,592	71,851,697	73,749,515	68,632,068	64,431,252	64,003,061	65,232,150
Gas Fuel Burn Expense													
Chehalis	37,613,211	4,019,654	2,777,042	2,744,208	2,532,999	2,151,598	3,240,462	3,385,317	2,482,829	3,284,894	3,295,509	3,593,139	4,105,560
Currant Creek	22,234,734	2,261,416	915,679	-	193,129	319,744	1,936,425	5,023,816	5,383,365	2,317,666	438,606	-	3,444,889
Gadsby	2,673,799	-	-	-	-	-	143,671	1,076,918	1,111,410	341,799	-	-	-
Gadsby CT	1,303,142	61,612	26,832	-	-	11,324	115,863	454,414	484,363	129,422	-	-	19,314
Hermiston	18,096,613	2,103,928	1,346,320	1,291,970	748,073	1,403,248	1,509,467	1,565,723	1,671,490	1,631,672	1,480,986	1,641,048	1,702,689
Lake Side 1	46,043,701	6,622,807	3,080,460	1,818,953	1,111,702	1,721,054	1,918,064	6,294,608	7,163,410	5,135,322	3,134,585	1,864,490	6,178,246
Lake Side 2	52,293,176	6,216,959	2,830,172	2,566,026	2,254,708	2,312,607	3,419,521	6,990,698	7,235,620	5,679,702	4,198,205	3,067,183	5,521,777
Total Gas Fuel Burn	180,258,378	21,286,375	10,976,505	8,421,157	6,840,611	7,919,574	12,283,472	24,791,494	25,532,487	18,520,477	12,547,892	10,165,860	20,972,474
Gas Physical	(127,586)	(45,477)	(41,034)	(41,075)	-	-	-	-	-	-	-	-	-
Gas Swaps	20,808,347	876,315	2,597,845	2,990,588	1,415,000	1,380,963	1,122,375	1,802,950	1,672,130	1,563,000	1,770,750	1,693,663	1,922,770
Clay Basin Gas Storage	352,571	(139,509)	(5,071)	9,448	52,242	52,242	52,242	52,242	52,242	52,242	52,242	47,447	74,560
Pipeline Reservation Fees	36,417,421	3,055,613	2,908,071	3,053,074	3,004,264	3,053,625	3,015,330	3,095,338	3,097,232	3,023,435	3,053,074	3,004,264	3,054,101
Total Gas Fuel Burn Expense	237,709,131	25,033,316	16,436,316	14,433,192	11,312,117	12,406,404	16,473,420	29,742,024	30,354,091	23,159,154	17,423,959	14,911,233	26,023,905

PacifiCorp

NPC Backcast 2017 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Other Generation													
Blundell	4,306,673	414,558	380,270	413,155	259,912	388,614	346,219	364,058	381,060	344,013	255,097	381,896	377,821
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	6,799,023	511,446	606,410	691,952	660,251	509,195	604,994	470,412	438,219	439,574	614,291	614,296	637,983
Total Other Generation	11,105,696	926,004	986,680	1,105,108	920,163	897,809	951,213	834,470	819,278	783,587	869,388	996,192	1,015,804
Net Power Cost	**1,525,294,643**	145,857,501	115,013,374	114,228,640	107,968,306	113,780,706	128,754,762	158,120,335	154,291,319	122,313,487	118,284,619	118,735,287	127,946,307

Docket No. UE 356
Exhibit PAC/110
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

April 2019

List of Known Items Expected to be Updated During the 2020 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			√	n/a				
	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	Wolverine/Sufco, Dugout, Skyline			√	√				
Huntington	Wolverine/Sufco, Dugout, Skyline			√	√				
	Rhino Energy/Castle Valley			n/a	√				
	Utah Trucking							√	√
D Johnston	Unidentified PRB					√	√		
	Peabody/N. Antelope Rochelle			n/a	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

REDACTED
Docket No. UE 356
Exhibit PAC/200
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Dana M. Ralston

April 2019

DIRECT TESTIMONY OF DANA M. RALSTON

TABLE OF CONTENTS

ATTACHED EXHIBITS

Highly Confidential Exhibit PAC/201 – Response to Partial Stipulation Item 16 – Update to PacifiCorp Long-Term Fuel Supply Plan for the Jim Bridger Plant – March 2019

Confidential Exhibit PAC/202 – Response to Partial Stipulation Item 18 – Bridger Coal Company Depreciation Expense

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.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I was previously 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 plant manager at the Neal Energy Center 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 provided testimony on behalf of the company in proceedings before the Public Utility Commission of Oregon (Commission) and the public utility commissions in Utah, Washington, California, 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 2020 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony:

- Discusses how PacifiCorp has complied with the Commission's order in the 2019 TAM requiring the company to prepare an additional analysis for the 2018 Jim Bridger Long-Term Fuel Plan (2018 Fuel Plan), and provides additional information on Bridger Coal Company depreciation expense;
- Explains the primary causes behind the changes to the total-company coal-fuel expense reflected in the 2020 TAM; and
- Provides coal pricing and background on third-party coal contracts and affiliate-owned mines.

COMPLIANCE WITH 2019 TAM ORDER

Q. In the partial stipulation in the 2019 TAM, did PacifiCorp agree to prepare an alternative analysis to evaluate the reasonableness of its Jim Bridger plant fueling strategy based on a 2030 useful life for the plant?

A. Yes. This agreement is reflected in paragraph 16 of the partial stipulation. The Commission approved the partial stipulation, including this provision, in Order No. 18-421.

Q. Has PacifiCorp complied with this requirement?

A. Yes. PacifiCorp prepared an alternative analysis based on a January 1, 2030 useful life for the Jim Bridger plant, instead of the 2037 date used for certain units in the 2018 Fuel Plan. PacifiCorp's alternative analysis results in the same fueling plan being selected as the least-cost, least-risk option when the plant life is shortened to 2030 to comply with Oregon Senate Bill 1547, validating the reasonableness of the company's plant fueling strategy. This alternative analysis is described in PacifiCorp's March 2019 Update to its 2018 Fuel Plan, attached as Exhibit PAC/201.

Q. In the partial stipulation, did PacifiCorp also agree to provide additional information on Bridger Coal Company depreciation expense?

A. Yes, this agreement is reflected in paragraph 18 of the partial stipulation approved in Order No. 18-421.

Q. Please explain how the company has complied with this requirement.

A. In Exhibit PAC/202, PacifiCorp has provided an explanation, schedule, and workpaper showing how depreciation expense for Bridger Coal Company's property, plant and equipment has changed since docket UE 263, the company's last Oregon rate case. The company used a forecast 2014 calendar year test period in that case.

OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supplies for its coal plants in 2020?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 84 percent of its 2020 coal requirements with third-party coal supplies and 16 percent with coal from its captive affiliate mines. More specifically: (1) 50.3 percent of the total coal requirement will be supplied from fixed-price contracts; (2) 21.5 percent will be supplied under variable-priced contracts that increase or decrease based on changes to producer and consumer price indices; and (3) 12.2 percent of the total coal requirement will be supplied from a contract for the Dave Johnston plant to be negotiated during 2019 as discussed later in my testimony.

Confidential Table 1: Coal Source Deliveries

	Plant	Price Reopener	New Contract	MMBtus (000s)	(000s)	Percent
Affiliate Mines						
Bridger Coal/Bridger	Jim Bridger			[redacted]		
Trapper Mining/Trapper	Craig			[redacted]		
Subtotal Affiliate Mines					[redacted]	16.0%
Fixed Price Contracts						
Lighthouse Resources/Black Butte	Jim Bridger			[redacted]		
Rhino Energy/Castle Valley	Huntington			[redacted]		
Wolverine/Sufco, Dugout, Skyline	Huntington			[redacted]		
Wolverine/Sufco, Dugout, Skyline	Hunter			[redacted]		
Peabody/Twentymile	Hayden			[redacted]		
Peabody/North Antelope Rochelle	Dave Johnston			[redacted]		
Subtotal Fixed Price Contracts					[redacted]	50.3%
Variable Price Contracts						
Peabody/El Segundo	Cholla			[redacted]		
Westmoreland/Rosebud	Colstrip			[redacted]		
Westmoreland/Kemmerer	Naughton			[redacted]		
Black Hills/Wyodak	Wyodak			[redacted]		
Subtotal Variable Price Contracts					[redacted]	21.5%
Other						
Unspecified PRB Mines	Dave Johnston		√	[redacted]		
Total Other					[redacted]	12.2%
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 2020 TAM decreased from the level reflected in PacifiCorp's 2019 TAM?

A. Yes. As stated in the testimony of company witness Mr. Michael G. Wilding, total coal-fuel expense has decreased by $73.3 million—from $743.1 million in the 2019 TAM final update to $669.8 million in this initial filing in the 2020 TAM.[1] This decrease is a result of an $83.7 million volume reduction in coal-fired generation,

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

partially offset by approximately $10.4 million in higher coal prices. These variances are shown in Confidential Table 2 below.

Confidential Table 2: Coal Fuel Variance - 2020 TAM vs. 2019 TAM

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

JIM BRIDGER FUEL SUPPLY

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company costs in the 2020 TAM.

A. Bridger Coal Company costs in the 2020 TAM are forecast to be [redacted] lower than the 2019 TAM. The cost for the base mine plan deliveries of [redacted] tons decrease by [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM as shown in Confidential Table 3. This results in a price decrease of [redacted] for the base mine plan. The decrease is primarily driven by a [redacted] [redacted] decrease in materials and supplies, [redacted] in changes due to coal inventory value, offset by a [redacted] increase in deferred longwall move cost amortization. [redacted] tons of supplemental coal is currently projected to be delivered in addition to the base mine plan, which is [redacted] tons fewer than the 2019 TAM. The reduced supplemental tons result in an unfavorable price variance of [redacted] due to lower volumes of supplemental coal.

Confidential Table 3: Jim Bridger Plant Coal Deliveries

	2020 TAM			2019 TAM			Variance			Price
	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Variance
Bridger Coal Deliveries	[redacted]			[redacted]			[redacted]			[redacted]
Bridger Base Mine Plan										
Supplemental Coal										
Total Bridger Coal										
Black Butte Deliveries										
Total Jim Bridger Plant										

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 captive mines.[2] In this filing, does PacifiCorp adjust the price of coal from Bridger Coal Company consistent with this order?**

A. Yes. In the 2020 TAM, the company reduces Bridger Coal Company costs by

[2] *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).

approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

Jim Bridger Third-Party Coal Supply

Q. What is the expected change in third-party coal prices for the Jim Bridger plant in the 2020 TAM?

A. Delivered costs for the [redacted] tons of Black Butte coal increased from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM, or [redacted] overall. As stipulated in the contract schedule, the price of Black Butte coal delivered to the Jim Bridger plant increases [redacted] per ton, from a cost of [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM. The coal price increase is approximately [redacted], or [redacted]. The Union Pacific Railroad agreement is forecast to increase by [redacted] in delivered costs.

THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in overall third-party coal-supply costs in the 2020 TAM.

A. PacifiCorp expects a net increase in third-party coal-supply costs of [redacted], as shown in Confidential Table 2 above. The details by plant are described below.

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Please describe the coal supply arrangement for the Naughton plant in 2020.

A. The Naughton plant is supplied by the adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The mine's former owner, Westmoreland Coal Company, filed bankruptcy in 2018, and is in the process of selling the mine to

Western Coal Acquisitions Partners pursuant to the plan recently approved by the bankruptcy court. The approved sale is still pending. The new owners have accepted the coal supply agreement as part of the bankruptcy proceeding and will continue to mine and sell coal under the terms of the current agreement after the sale has closed. The coal supply agreement calculates tier-1 and tier-2 volumes and pricing based on a July-to-June contract year. 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 Naughton Unit 3 discontinuing as a coal-fired resource in January 2019, 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 2020 related to [redacted] shortfall tons on deliveries of [redacted] tons in the 2019-2020 contract year. The environmental shortfall payment is a direct result of the reduction in the coal purchases due to Naughton Unit 3 discontinuing as a coal-fired unit.

Q. Please describe the Naughton plant's coal cost change from the 2019 TAM.

A. Total delivered coal cost at Naughton increased [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM [redacted] overall), as shown in Confidential Table 4. The 2020 price forecast is based upon the actual mining costs at the Kemmerer mine for calendar year 2018 escalated based upon projected diesel fuel prices as well as producer and consumer price indices. The contract escalation results in a price increase of [redacted] after royalties and taxes. Another major driver of the price increase is a [redacted] increase in the environmental shortfall payment, from [redacted] in 2019 to [redacted] in 2020. Because Unit 3 closed in January 2019 and the shortfall payment is calculated based upon the contract year, the 2019 TAM shortfall payment included an amount for only 5 months. The change in the amount of coal purchased under each price tier—namely more tier-2 coal, which is lower priced coal than tier-1 coal—is the driver of savings of [redacted]. The forecasted tier-2 coal delivered in calendar year 2020 is [redacted] tons more than 2019.

Confidential Table 4: Naughton Contract Tonnage and Pricing

	2020 TAM			2019 TAM			Variance		
Contract Tiers	Tons	Dollars	Price	Tons	Dollars	Price	Tons	Dollars	Price
Naughton Plant	[redacted]			[redacted]			[redacted]		
Tier 1									
Tier 2									
Subtotal									
Other Coal Costs									
Environmental Shortfall		[redacted]			[redacted]			[redacted]	
Kemmerer Btu Adjustment									
Iron & Calcium Premiums									
Subtotal									
Total Naughton	[redacted]								
Btu/lb			[redacted]			[redacted]			[redacted]
$/MMBtu									

Wyodak

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

A. Delivered coal cost increased from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM, or [redacted] overall. The cost increase is primarily the result of escalation in diesel fuel and other contract indices.

Dave Johnston

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

A. Dave Johnston plant delivered coal cost increased by [redacted] compared to the 2019 TAM, or [redacted]. The increase is due to an increase in coal costs of [redacted], as described in further detail below, partially offset by rail cost decrease of approximately [redacted].

Q. Please describe 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 2020; the company currently has [redacted] tons of coal under contract for the plant resulting in an unidentified or open position of [redacted] tons. The company will solicit coal supplies from Powder River Basin (PRB) mines through a request for proposals during 2019 to fill a reasonable portion of the open position, which may be adjusted according to market conditions. The company has used this fueling strategy for the Dave Johnston plant for several years.

Q. What are the coal supply arrangements for the Dave Johnston plant in the 2020 TAM?

A. Peabody Energy's North Antelope Rochelle mine will supply [redacted] tons in 2020 ([redacted] of the plant's requirements). The coal price for the Dave Johnston plant's open position of approximately [redacted] tons in the 2020 TAM reflects the average 2020 forward price for PRB 8400 Btu coal of [redacted] per ton, as published in Coal Daily in February 2019. The 2020 price is [redacted] higher than the 2019 PRB 8400 Btu price of [redacted] per ton that was used for the open position in the 2019 TAM and [redacted] higher than the Dry Fork mine price of [redacted] per ton in the 2019 TAM which will expire in December 2019. The rail cost decrease of [redacted] is primarily a result of a shorter distance that the spot coal is forecasted to be purchased from than the prior Dry Fork coal contract.

Coal Supply Agreements for the Utah Plants

Hunter

Q. Please explain how the company's Hunter plant is supplied with coal in the 2020 TAM.

A. The primary coal supply for the Hunter plant is provided through a coal supply agreement with Wolverine Fuels, LLC (Wolverine) formerly known as Bowie Resource Partners. The Hunter agreement is a "delivered to plant" agreement through 2020, and Wolverine is responsible for the transportation of the coal from the mine to the plant.

Q. Please describe the change in coal costs at the Hunter plant in the 2020 TAM.

A. Coal prices have increased [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM [redacted] overall). The increase is primarily due to the annual inflation-index escalation under the Wolverine agreement ([redacted]), partially offset by a savings of [redacted] due to an additional [redacted] tons of tier-2 coal delivered in 2020.

Huntington

Q. Please describe the coal supply arrangement for the Huntington plant in 2020.

A. The primary coal supply to the Huntington plant is also provided under a contract with Wolverine. This is also a "delivered to the plant" agreement that requires

Wolverine to pay the transportation costs, although 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. What coal supply costs for the Huntington plant are included in the 2020 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM, an overall increase of [redacted] per ton or [redacted] for the weighted average price of the Castle Valley and Wolverine mines. The overall price per ton for the Wolverine contract increased [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM, [redacted] overall on [redacted] tons. The Wolverine price is higher in 2020 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 2019 TAM to [redacted] per ton in the 2020 TAM [redacted] overall). The Castle Valley price is higher in 2020 primarily due to the annual escalation schedule as stipulated in the contract. The Castle Valley mine supplies [redacted] tons of coal annually to the Huntington plant.

Q. Does the 2020 TAM reflect Energy West pension costs?

A. Yes. As authorized under Order No. 15-161 in docket UM 1712, the 2020 TAM includes [redacted] for contributions to the 1974 United Mine Workers Association pension plan.[3] [redacted] is included in Huntington plant costs in the 2020 TAM, consistent with the 2019 TAM. [redacted] of the [redacted] in pension costs is

[3] *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).

included in Hunter plant costs in the 2020 TAM, consistent with the 2019 TAM.

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 Energy'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.

Q. What price does PacifiCorp assume for the Cholla coal supply in the 2020 TAM?

A. PacifiCorp forecasts that the delivered coal price at the Cholla plant will increase [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the current 2020 TAM [redacted] overall). The coal supply agreement accounts for [redacted] of the increase and a rail cost increase of [redacted]. The coal supply cost increase of [redacted] is mainly attributable to escalation in diesel fuel and other producer and consumer price indices under the agreement.

The [redacted] rail cost increase is primarily a result of the set contract escalation of [redacted] percent plus fuel surcharges. The 2020 TAM assumes that the [redacted].

Craig

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

A. In 2020, the Craig plant will be supplied by the Trapper mine, which is an affiliate captive mine owned by four of the five 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 2019 TAM?

A. Yes. Trapper mine costs have decreased [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM, a [redacted] overall price decrease. The majority of this is due to a federal royalty rate reduction. Deliveries from Trapper mine have increased [redacted] from [redacted] tons in the 2019 TAM to [redacted] tons in the 2020 TAM.

Hayden

Q. Please describe the change in Hayden plant's coal cost in the 2020 TAM.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2019 TAM to [redacted] per ton in the 2020 TAM, an increase of [redacted]. Under the terms of the January 1, 2018 reopener, the coal prices escalate on a fixed annual 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 2020 TAM.

A. Coal prices for the Colstrip plant are [redacted] per ton in the 2020 TAM. PacifiCorp developed the 2020 TAM costs for the Colstrip plant based on the 2019 Annual Operating Plan (AOP) for the Rosebud mine from Western Energy Company, the mine's previous owner. The AOP is reviewed and approved annually by the owners of Colstrip Units 3 and 4. The current contract with Western Energy expires at the end of 2019. As noted above, Westmoreland Coal, Western Energy's parent company, filed bankruptcy in 2018 and the Rosebud mine has recently been sold to new ownership. [redacted]

[redacted]

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, as shown in Confidential Table 2 above. PacifiCorp's fueling strategy has resulted in long-term, stable, low-cost coal supplies for its customers.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 356
Exhibit PAC/201
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

Update to PacifiCorp Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant

April 2019

UPDATE TO
PACIFICORP CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIGER PLANT

March 2019

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

INTRODUCTION

In March 2018, PacifiCorp filed the "PacifiCorp Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" (2018 Fuel Plan) as Exhibit PAC/204 in Oregon docket UE 339, PacifiCorp's 2019 Transition Adjustment Mechanism (TAM). The purpose of the 2018 Fuel Plan was to determine the least-cost, least-risk coal supply for the Jim Bridger plant evaluated on a multi-year basis. Subsequent to filing the 2018 Fuel Plan, the Public Utility Commission of Oregon (Oregon Commission) approved a partial stipulation in Order No. 18-421, which required PacifiCorp to develop an alternative analysis to evaluate the reasonableness of the company's fueling strategy based upon a shortened plant life of January 1, 2030, instead of 2037. The shortened plant life is tied to compliance with Oregon Senate Bill 1547, not to planning assumptions reflected in PacifiCorp's 2017 Integrated Resource Plan (IRP).

BACKGROUND

The Jim Bridger plant's current fuel supply is comprised of coal from PacifiCorp's captive Bridger mine and coal from the nearby Black Butte mine, owned by Lighthouse Resources. The 2018 Fuel Plan was designed to ensure that fuel supplies are reasonable and prudent, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

In developing the 2018 Fuel Plan, PacifiCorp studied, reviewed, and evaluated different fueling options based upon certain generation assumptions for the Jim Bridger plant. The generation assumptions used in the 2018 Fuel Plan were taken from PacifiCorp's GRID model used for budget and planning, and paralleled PacifiCorp's 2017 IRP Update. The generation assumptions assumed the closure of Jim Bridger Unit 1 on December 31, 2028, and Jim Bridger Unit 2 on December 31, 2032. Jim Bridger Units 3 and 4 closure dates were assumed to be December 31, 2037.

PacifiCorp ultimately narrowed its review to six different fueling options that considered varying tonnage delivery schedules being sourced from Bridger Coal Company (BCC or Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB), which are 8,800 British thermal unit per pound (Btu/lb.) mines. Additionally, the different coal delivery options for the Bridger mine contained various mine plan scenarios outlining specified tonnage delivery schedules from both the underground and surface mining operations. Included in these different mine scenarios were estimated shutdown dates for Bridger mine's underground and surface operations. The 2018 Fuel Plan provided third-party coal supply tonnages and pricing estimates along with estimated rail rates for transportation services for the transport of third-party coal. Finally, the 2018 Fuel Plan provided estimated plant modifications and capital requirements needed to support coal deliveries from the SPRB.

After considering all of the factors influencing the long-term fueling strategy, the company evaluated the six different fueling options. Based upon the results of a detailed present value revenue requirement (PVRR) analysis, Option F (Bridger Coal Delivers [redacted] tons/year) was determined to be the least-cost, least-risk option and the strategy that PacifiCorp selected to follow. The specific assumptions associated with Option F (Bridger Coal Delivers [redacted] tons/year) are noted below.

[redacted]

A comprehensive detailed description of all six options and the original PVRR analysis is found in the 2018 Fuel Plan.

ALTERNATIVE ANALYSIS ASSUMPTIONS

With the shortened plant life, the alternative analysis only considered four of the prior six options. Two of the options in the 2018 Fuel Plan assumed that the [redacted] Additionally, the depreciation associated with any new plant capital has been accelerated to account for the shortened plant life and external fuel purchases cease at the end of 2029. With these new assumptions, the company calculated a new PVRR analysis as shown in Table 1 below.

PVRR ANALYSIS & RESULTS

The results of the PVRR analysis substantiate that Option F (Bridger Coal Delivers [redacted] tons/year) is the least cost option under the shortened life evaluation. Option F (Bridger Coal Delivers [redacted] tons/year) is [redacted] dollars less than the next closest option of Option F (PRB). It is [redacted] dollars less than the most expensive option of Option F (Bridger Coal Delivered [redacted] tons/year). The specific ranking of the analysis is shown in Confidential Table 1 below.

Confidential Table 1

PVRR Summary PAC Portion		PVRR 000's	PVRR Differential (from lowest $)	Financial Ranking (low to high)	Percent Change	Plant Capital (w/AFUDC and esclation, 000'S)	Bridger Coal Capital (2018-LOM in-service, escalated, 000's)

[redacted]

CONCLUSION

The results of the alternative analysis further substantiate that Option F (Bridger Coal Delivers [redacted] tons/year) is the least-cost, least-risk option and the right strategy for PacifiCorp, even with a shortened plant life of January 1, 2030. 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. Fueling the plant with predominantly regional coal from the Bridger mine and the Black Butte mine provides benefits to PacifiCorp's customers by (1) providing a least-cost, least-risk fuel supply, (2) avoiding large capital expenditures, and (3) allowing PacifiCorp to [redacted].

REDACTED
Docket No. UE 356
Exhibit PAC/202
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

Response to Partial Stipulation Item 18 – Bridger Coal Company Depreciation Expense

April 2019

REDACTED

Public Utility Commission of Oregon (OPUC)
Docket UE 339
Partial Stipulation dated July 23, 2018
Item Number 18 - Bridger Coal Company (BCC) Depreciation Expense

This BCC depreciation summary and workpaper provides information required by the partial stipulation approved by the OPUC in PacifiCorp's 2019 Transition Adjustment Mechanism (TAM) Docket UE 339. The partial stipulation requires that PacifiCorp:

(1) Include information setting forth how and why BCC depreciation expense has changed from levels set in the most recent general rate case,
(2) Provide workpapers in future TAM filings to support depreciable lives of BCC assets and,
(3) Continue to work together to determine the types of depreciation workpapers to be included in future TAM filings.

Property, Plant & Equipment (PP&E) Roll-Forward Schedule

Confidential Table 1 below provides property, plant and equipment information from BCC at 100 percent, not the PacifiCorp two-thirds share. This schedule begins in 2014 which was the most recent PacifiCorp general rate case, docket UE 263, which was filed in 2013 and used a forecast 2014 calendar year test period. The schedule shows actual plant asset investment, additions, and retirements from 2014 through 2018 and forecast values in 2019 through 2020. A workpaper for this schedule is included with the filing.

Confidential Table 1: Bridger Coal Company Net Plant Investment

Bridger Coal Company Net Plant Investment (000s)	1/1/2014 12/31/2014 (actual)	1/1/2015 12/31/2015 (actual)	1/1/2016 12/31/2016 (actual)	1/1/2017 12/31/2017 (actual)	1/1/2018 12/31/2018 (actual)	1/1/2019 12/31/2019 (estimate)	1/1/2020 12/31/2020 (estimate)
Begin Net Plant Invest	[redacted]						
Plant Additions							
Retirements (loss)							
Depreciation Expense							
End Net Plant Invest							

- Plant Additions:
  - For the four years from 2014 to 2017, plant additions averaged [redacted].
  - During 2015, a longwall mining system costing [redacted] was added. Excluding this major addition, the plant additions for this year would have been [redacted] and the four-year average would have been [redacted].
  - For the three years from 2018 to 2020, additions drop to an average of [redacted] as a result of changes to long-term mining plans.
- Depreciation Expense:
  - Over the seven years reflected in the schedule above, depreciation averaged [redacted] annually.
  - In 2017, this average increased to [redacted]. This was primarily driven by the accelerated depreciation for the underground mine's west district infrastructure due to the early withdrawal from that area of the mine.
- Plant Retirements:

- This line reflects the net book value of assets retired before being fully depreciated, typically resulting in a loss.
- A loss occurred in October 2016 as a result of the retirement of the shuttered longwall system.

Depreciation Lives

PP&E investment is segregated into three major groups:

(1) Surface mine assets
(2) Underground mine assets
(3) Administrative assets – this group is comprised of assets that functionally benefit both surface and underground operations.

Each of these asset groups can be further divided into two classifications:

(1) Life of mine assets
   - Structures: offices, shops, processing facilities etc.
   - Improvements: roads, electrical power lines, and drainage / water control facilities
   - Mine development: box-cuts, exploration drilling, slope stabilization, etc.

(2) Equipment used in the extraction of coal or in a support capacity

Equipment estimated lives are based on or influenced by the following:

- Industry standards
- Manufacturer recommendations
- Equipment operating hours and conditions
- Asset type
  - Life-of-mine – buildings, structures, development, etc.
  - Equipment – subject to wear/deterioration
  - Obsolescence – changes in technology, parts availability, vendor support
- Long-term fueling plan requirements
- Risk/Impairment

Industry Standards / Manufacturer Recommendations

Industry standards and manufacturer recommendations have historically influenced the selection of the depreciable life basis for major fleet equipment. An awareness of industry standards is obtained from discussions with contacts with other mining companies and manufacturer representatives. The information presented below identifies the depreciable lives of commonly used equipment in mines located in the western United States.

Book Depreciable Life Summary - Surface Mine, Rolling Stock					
Fleet	Bridger Coal Company	Trapper Mining Company [(a)]	Black Butte Coal Company	Westmoreland's Rosebud Mine	Peabody's El Segundo Mine [(a)]
Haul Trucks	10 yrs.	7 -12 yrs.	12 yrs.	10 yrs.	12 yrs.
Dozers	10 yrs.	7 -12 yrs.	10 yrs.	10 yrs.	6 yrs.
Drills	10 yrs.	7 -12 yrs.	10 yrs.	10 yrs.	12-15 yrs.
Loaders	10 yrs.	7 -12 yrs.	10 yrs.	10 yrs.	6 yrs.
Graders	10 yrs.	7 -12 yrs.	10 yrs.	10 yrs.	

[(a)]Varies based on past history, manufacturer's recommendations, operating hours, etc.

Equipment Type and Usage
Asset type and equipment usage are considered when assigning depreciable life to each asset. For example:

- Buildings and structures are generally depreciated over the mine's life
- Major mining equipment is better suited to cope with harsh mining conditions than lightly constructed vehicles and thus have different book lives.
- Light and medium duty vehicles operating on improved roadways operate for more years or miles than those same vehicles operated only within mine boundaries.
- Conveyor belts with shorter lengths generally have a reduced useful life as compared to belting with longer lengths. This is due to belting being subject to more tension as the belt is redirected from wrapping around the drive pulley assembly more frequently.
- Electronic assets can vary and are dependent on whether the asset is used in the mine or in an office environment.
- Electronic equipment is more susceptible to changes in technology resulting in lack of vendor support and obsolescence.

Long-Term Plans, Market Risk
The energy sector has experienced rapid and significant changes over the past decade. Some of these changes are driven by low natural gas prices and the availability of renewable energy. The demand for electricity output at the Jim Bridger plant has been impacted. In 2017, the plant produced 11.6 million MWhs which is 21.5 percent less than in 2010. In early 2018, an updated confidential long-term fueling plan for the Jim Bridger plant was provided to the Public Utility Commission of Oregon. The least-cost, least-risk option being pursued by BCC owners results in mine closure sooner than was projected in prior fueling plans. Assumptions in the confidential long-term fueling plan are aligned with those in the 2017 IRP.

Depreciation Methodology
Depreciation expense, for most assets, is calculated using a straight line method. Electric utilities typically use the "group method" which depreciates an entire set of related assets as a single entity rather than individually. The straight line methodology depreciates assets on an individual basis and is calculated by spreading an asset's gross cost evenly over the assigned depreciable life.

There are two exceptions to the straight line method for BCC assets:

- Longwall section equipment depreciation expense is calculated by multiplying the number of cycles operated during an accounting period by a rate per cycle. The rate per cycle is determined by dividing the longwall's cost by the number of cycles it is expected to operate.
- Coal reserve depletion expense is calculated by multiplying the number of tons produced during an accounting period by a rate per ton. The rate per ton is determined by dividing the cost to acquire the reserves by the number of tons expected to be extracted from the reserve.

Summary
A reasonable and conservative approach has been taken when assigning depreciable lives to mining assets. Various factors are considered to achieve a balanced outcome for customers and owners. This approach encourages appropriate cost recognition, minimizes impairment risk and is consistent with industry standards.

Docket No. UE 356
Exhibit PAC/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

April 2019

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

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ATTACHED EXHIBITS

Exhibit PAC/301—Proposed TAM Rate Spread and Rates

Exhibit PAC/302—Proposed TAM Adjustment for Other Revenues

Exhibit PAC/303—Proposed Tariff Schedules

Exhibit PAC/304—Estimated Effect of Proposed TAM Price Change

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 2020 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and the TAM adjustment 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, 2020.

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.

[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] and were not updated in the company's most recent TAM filing. PacifiCorp proposes adders to the present Schedule 205 rates reflecting the adjustment related to other revenues described in Mr. Wilding's testimony. The proposed rate spread and rate design for the Schedule 205 adders parallels the generation-based rate spread and rate design of Schedule 201 for NPC as described above, consistent with past treatment of this adjustment.

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

A. Yes. Exhibit PAC/302 shows the proposed adjustments to Schedule 205 rates and revenues based on the amounts in the 2020 TAM for other revenues along with the total combined Schedule 205 rates for the tariff, which reflect the present Schedule 205 rates plus the additional adjustment for this TAM.

[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).

Q. Please describe Exhibit PAC/303.

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

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

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

Q. Are there other tariff changes which will be made in the compliance filing in this docket?

A. Yes. The company will file Schedule 293 to reflect any changes to the Company Supply Service Access Charge and Schedule 220 to reflect updated market weightings based on the final TAM results in November.

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 decrease of 1.2 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/304 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 and Schedule 205?

A. Yes. Exhibit PAC/304, 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 850 kilowatt-hours per month is a bill decrease of $0.91.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 356
Exhibit PAC/301
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

April 2019

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2020

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Present Rate Spread	Target Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	4,004,325,448	2.619 ¢	$104,873,283	28.4807%	$100,691,946	2.515 ¢	$100,708,785
Second Block kWh (> 1,000)	1,412,584,596	3.579 ¢	$50,556,403	13.7297%	$48,540,700	3.436 ¢	$48,536,407
	5,416,910,044		$155,429,686		$149,232,646		$149,245,192
						Change	-$6,184,494
Employee Discount							
First Block kWh (0-1,000)	11,574,326	2.619 ¢	$303,132			2.515 ¢	$291,094
Second Block kWh (> 1,000)	5,448,813	3.579 ¢	$195,013			3.436 ¢	$187,221
	17,023,139		$498,145				$478,315
Discount			-$124,536				-$119,579
						Change	$4,958
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	896,080,332	2.902 ¢	$26,004,251	7.0620%	$24,967,452	2.786 ¢	$24,964,798
All additional kWh, per kWh	240,447,898	2.151 ¢	$5,172,034	1.4046%	$4,965,823	2.065 ¢	$4,965,249
	1,136,528,230		$31,176,285		$29,933,275		$29,930,047
						Change	-$1,246,238
Primary Voltage							
1st 3,000 kWh, per kWh	750,730	2.810 ¢	$21,096	0.0057%	$20,255	2.698 ¢	$20,255
All additional kWh, per kWh	326,780	2.085 ¢	$6,813	0.0019%	$6,541	2.002 ¢	$6,542
	1,077,510		$27,909		$26,796		$26,797
						Change	-$1,112
Schedule 28, General Service 31-200kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	1,424,579,038	2.838 ¢	$40,429,553	10.9796%	$38,817,612	2.725 ¢	$38,819,779
All additional kWh, per kWh	581,528,275	2.758 ¢	$16,038,550	4.3556%	$15,399,087	2.648 ¢	$15,398,869
	2,006,107,313		$56,468,103		$54,216,699		$54,218,648
						Change	-$2,249,455
Primary Voltage							
1st 20,000 kWh, per kWh	9,700,334	2.731 ¢	$264,916	0.0719%	$254,354	2.622 ¢	$254,343
All additional kWh, per kWh	8,760,429	2.658 ¢	$232,852	0.0632%	$223,568	2.552 ¢	$223,566
	18,460,763		$497,768		$477,922		$477,909
						Change	-$19,859
Schedule 30, General Service 201-999kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	177,461,657	3.033 ¢	$5,382,412	1.4617%	$5,167,813	2.912 ¢	$5,167,683
All additional kWh, per kWh	1,052,282,240	2.629 ¢	$27,664,500	7.5129%	$26,561,506	2.523 ¢	$26,549,081
	1,229,743,897		$33,046,912		$31,729,319		$31,716,764
						Change	-$1,330,148
Primary Voltage							
1st 20,000 kWh, per kWh	12,092,595	3.000 ¢	$362,778	0.0985%	$348,314	2.880 ¢	$348,267
All additional kWh, per kWh	78,313,160	2.593 ¢	$2,030,660	0.5515%	$1,949,697	2.490 ¢	$1,949,998
	90,405,755		$2,393,438		$2,298,011		$2,298,265
						Change	-$95,173
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
Winter, 1st 100 kWh/kW, per kWh	2,889,434	4.051 ¢	$117,051	0.0318%	$112,384	3.889 ¢	$112,370
Winter, All additional kWh, per kWh	2,402,914	2.759 ¢	$66,296	0.0180%	$63,653	2.649 ¢	$63,653
Summer, All kWh, per kWh	215,037,274	2.759 ¢	$5,932,878	1.6112%	$5,696,332	2.649 ¢	$5,696,337
	220,329,622		$6,116,225		$5,872,369		$5,872,360
						Change	-$243,865
Primary Voltage							
Winter, 1st 100 kWh/kW, per kWh	10,806	3.919 ¢	$423	0.0001%	$406	3.758 ¢	$406
Winter, All additional kWh, per kWh	61,803	2.673 ¢	$1,652	0.0004%	$1,586	2.566 ¢	$1,586
Summer, All kWh, per kWh	384,137	2.673 ¢	$10,268	0.0028%	$9,859	2.566 ¢	$9,857
	456,746		$12,343		$11,851		$11,849
						Change	-$494
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	26,876,795	2.481 ¢	$666,813			2.383 ¢	$640,474
Off-Peak, per off-peak kWh	8,860,497	2.431 ¢	$215,399			2.333 ¢	$206,715
	35,737,292		$882,212		$847,189		$847,189
						Change	-$35,023
Transmission Voltage							
On-Peak, per on-peak kWh	5,408,018	2.330 ¢	$126,007			2.238 ¢	$121,031
Off-Peak, per off-peak kWh	6,693,672	2.280 ¢	$152,616			2.188 ¢	$146,458
	12,101,690		$278,623		$267,489		$267,489
						Change	-$11,134

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2020

		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	355,680,704	2.674	¢	$9,510,902	2.5829%	$9,131,699	2.568	¢	$9,133,880
Off-Peak, per off-peak kWh	196,125,707	2.624	¢	$5,146,339	1.3976%	$4,941,153	2.518	¢	$4,938,445
	551,806,411			$14,657,241		$14,072,851			$14,072,325
							Change		-$584,916
Primary Voltage									
On-Peak, per on-peak kWh	1,032,320,231	2.481	¢	$25,611,865	6.9555%	$24,590,710	2.383	¢	$24,600,191
Off-Peak, per off-peak kWh	649,820,198	2.431	¢	$15,797,129	4.2901%	$15,167,292	2.333	¢	$15,160,305
	1,682,140,429			$41,408,994		$39,758,002			$39,760,496
							Change		-$1,648,498
Transmission Voltage									
On-Peak, per on-peak kWh	638,904,002	2.330	¢	$14,886,463	4.0428%	$14,292,934	2.238	¢	$14,298,672
Off-Peak, per off-peak kWh	485,619,771	2.280	¢	$11,072,131	3.0069%	$10,630,681	2.188	¢	$10,625,361
	1,124,523,773			$25,958,594		$24,923,615			$24,924,033
							Change		-$1,034,561
Schedule 15, Outdoor Area Lighting Service									
Secondary Voltage									
All kWh, per kWh	8,880,371	2.182	¢	$193,850	0.0526%	$186,121	2.096	¢	$186,019
	8,880,371			$193,850		$186,121			$186,019
							Change		-$7,831
Schedule 50, Mercury Vapor Street Lighting Service									
Secondary Voltage									
All kWh, per kWh	7,832,744	1.799	¢	$141,084	0.0383%	$135,459	1.729	¢	$135,071
	7,832,744			$141,084		$135,459			$135,071
							Change		-$6,014
Schedule 51, Street Lighting Service, Company-Owned System									
Secondary Voltage									
All kWh, per kWh	19,135,009	2.838	¢	$543,053	0.1475%	$521,401	2.725	¢	$521,627
	19,135,009			$543,053		$521,401			$521,627
							Change		-$21,426
Schedule 52, Street Lighting Service, Company-Owned System									
Secondary Voltage									
All kWh, per kWh	989,748	2.174	¢	$21,517	0.0058%	$20,659	2.087	¢	$20,656
	989,748			$21,517		$20,659			$20,656
							Change		-$861
Schedule 53, Street Lighting Service, Consumer-Owned System									
Secondary Voltage									
All kWh, per kWh	11,893,740	0.926	¢	$110,136	0.0299%	$105,745	0.889	¢	$105,735
	11,893,740			$110,136		$105,745			$105,735
							Change		-$4,401
Schedule 54, Recreational Field Lighting									
Secondary Voltage									
All kWh, per kWh	1,383,326	1.599	¢	$22,119	0.0060%	$21,237	1.535	¢	$21,234
	1,383,326			$22,119		$21,237			$21,234
							Change		-$885
Total before Employee Discount				**$369,386,092**	100.0000%	$354,658,656			**$354,659,705**
Employee Discount				-$124,536		-$119,579			-$119,579
TOTAL	**13,576,444,413**			**$369,261,556**		$354,539,078			**$354,540,126**
							Change		**-$14,721,430**
Schedule 47 Unscheduled kWh	2,664,418								
Total Forecast kWH	13,579,108,831								

Docket No. UE 356
Exhibit PAC/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Adjustment for Other Revenues

April 2019

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Revenues
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2020

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues Rates	Revenues	Total Proposed Schedule 205 Rates
Schedule 4, Residential						
First Block kWh (0-1,000)	4,004,325,448	0.019 ¢	28.4807%	0.000 ¢	$0	0.019 ¢
Second Block kWh (> 1,000)	1,412,584,596	0.026 ¢	13.7297%	0.001 ¢	$14,126	0.027 ¢
	5,416,910,044				$14,126	
Employee Discount						
First Block kWh (0-1,000)	11,574,326			0.000 ¢	$0	
Second Block kWh (> 1,000)	5,448,813			0.001 ¢	$54	
	17,023,139				$54	
Discount					-$14	
Schedule 23, Small General Service						
Secondary Voltage						
1st 3,000 kWh, per kWh	896,080,332	0.022 ¢	7.0620%	0.001 ¢	$8,961	0.023 ¢
All additional kWh, per kWh	240,447,898	0.016 ¢	1.4046%	0.001 ¢	$2,404	0.017 ¢
	1,136,528,230				$11,365	
Primary Voltage						
1st 3,000 kWh, per kWh	750,730	0.021 ¢	0.0057%	0.001 ¢	$8	0.022 ¢
All additional kWh, per kWh	326,780	0.015 ¢	0.0019%	0.000 ¢	$0	0.015 ¢
	1,077,510				$8	
Schedule 28, General Service 31-200kW						
Secondary Voltage						
1st 20,000 kWh, per kWh	1,424,579,038	0.020 ¢	10.9796%	0.001 ¢	$14,246	0.021 ¢
All additional kWh, per kWh	581,528,275	0.019 ¢	4.3556%	0.001 ¢	$5,815	0.020 ¢
	2,006,107,313				$20,061	
Primary Voltage						
1st 20,000 kWh, per kWh	9,700,334	0.020 ¢	0.0719%	0.001 ¢	$97	0.021 ¢
All additional kWh, per kWh	8,760,429	0.019 ¢	0.0632%	0.000 ¢	$0	0.019 ¢
	18,460,763				$97	
Schedule 30, General Service 201-999kW						
Secondary Voltage						
1st 20,000 kWh, per kWh	177,461,657	0.022 ¢	1.4617%	0.001 ¢	$1,775	0.023 ¢
All additional kWh, per kWh	1,052,282,240	0.019 ¢	7.5129%	0.001 ¢	$10,523	0.020 ¢
	1,229,743,897				$12,298	
Primary Voltage						
1st 20,000 kWh, per kWh	12,092,595	0.021 ¢	0.0985%	0.001 ¢	$121	0.022 ¢
All additional kWh, per kWh	78,313,160	0.019 ¢	0.5515%	0.000 ¢	$0	0.019 ¢
	90,405,755				$121	
Schedule 41, Agricultural Pumping Service						
Secondary Voltage						
Winter, 1st 100 kWh/kW, per kWh	2,889,434	0.029 ¢	0.0318%	0.001 ¢	$29	0.030 ¢
Winter, All additional kWh, per kWh	2,402,914	0.020 ¢	0.0180%	0.001 ¢	$24	0.021 ¢
Summer, All kWh, per kWh	215,037,274	0.020 ¢	1.6112%	0.001 ¢	$2,150	0.021 ¢
	220,329,622				$2,203	
Primary Voltage						
Winter, 1st 100 kWh/kW, per kWh	10,806	0.028 ¢	0.0001%	0.001 ¢	$0	0.029 ¢
Winter, All additional kWh, per kWh	61,803	0.019 ¢	0.0004%	0.000 ¢	$0	0.019 ¢
Summer, All kWh, per kWh	384,137	0.019 ¢	0.0028%	0.000 ¢	$0	0.019 ¢
	456,746				$0	
Schedule 47, Large General Service, Partial Requirements 1,000kW and over						
Primary Voltage						
On-Peak, per on-peak kWh	26,876,795	0.017 ¢		0.000 ¢	$0	0.017 ¢
Off-Peak, per off-peak kWh	8,860,497	0.017 ¢		0.000 ¢	$0	0.017 ¢
	35,737,292				$0	
Transmission Voltage						
On-Peak, per on-peak kWh	5,408,018	0.016 ¢		0.000 ¢	$0	0.016 ¢
Off-Peak, per off-peak kWh	6,693,672	0.016 ¢		0.000 ¢	$0	0.016 ¢
	12,101,690				$0	

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Revenues
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2020

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues: Rates	Proposed Adj. to Schedule 205 for Other Revenues: Revenues	Total Proposed Schedule 205 Rates
Schedule 48, Large General Service, 1,000kW and over						
Secondary Voltage						
On-Peak, per on-peak kWh	355,680,704	0.019 ¢	2.5829%	0.001 ¢	$3,557	0.020 ¢
Off-Peak, per off-peak kWh	196,125,707	0.019 ¢	1.3976%	0.001 ¢	$1,961	0.020 ¢
	551,806,411				$5,518	
Primary Voltage						
On-Peak, per on-peak kWh	1,032,320,231	0.017 ¢	6.9555%	0.000 ¢	$0	0.017 ¢
Off-Peak, per off-peak kWh	649,820,198	0.017 ¢	4.2901%	0.000 ¢	$0	0.017 ¢
	1,682,140,429				$0	
Transmission Voltage						
On-Peak, per on-peak kWh	638,904,002	0.016 ¢	4.0428%	0.000 ¢	$0	0.016 ¢
Off-Peak, per off-peak kWh	485,619,771	0.016 ¢	3.0069%	0.000 ¢	$0	0.016 ¢
	1,124,523,773				$0	
Schedule 15, Outdoor Area Lighting Service						
Secondary Voltage						
All kWh, per kWh	8,880,371	0.016 ¢	0.0526%	0.000 ¢	$0	0.016 ¢
	8,880,371				$0	
Schedule 50, Mercury Vapor Street Lighting Service						
Secondary Voltage						
All kWh, per kWh	7,832,744	0.013 ¢	0.0383%	0.000 ¢	$0	0.013 ¢
	7,832,744				$0	
Schedule 51, Street Lighting Service, Company-Owned System						
Secondary Voltage						
All kWh, per kWh	19,135,009	0.019 ¢	0.1475%	0.001 ¢	$191	0.020 ¢
	19,135,009				$191	
Schedule 52, Street Lighting Service, Company-Owned System						
Secondary Voltage						
All kWh, per kWh	989,748	0.016 ¢	0.0058%	0.000 ¢	$0	0.016 ¢
	989,748				$0	
Schedule 53, Street Lighting Service, Consumer-Owned System						
Secondary Voltage						
All kWh, per kWh	11,893,740	0.007 ¢	0.0299%	0.000 ¢	$0	0.007 ¢
	11,893,740				$0	
Schedule 54, Recreational Field Lighting						
Secondary Voltage						
All kWh, per kWh	1,383,326	0.010 ¢	0.0060%	0.000 ¢	$0	0.010 ¢
	1,383,326				$0	
Total before Employee Discount			**100.0000%**		**$65,988**	
Employee Discount					-$14	
TOTAL	**13,576,444,413**				**$65,975**	

Schedule 47 Unscheduled kWh	2,664,418
Total Forecast kWH	13,579,108,831

Docket No. UE 356
Exhibit PAC/303
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedules

April 2019

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	2.515¢			(R)
		> 1000 kWh	3.436¢			
5	Per kWh	0-1000 kWh	2.515¢			
		> 1000 kWh	3.436¢			(R)

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

		Secondary	Primary	Transmission	
23	First 3,000 kWh, per kWh	2.786¢	2.698¢		(R)
	All additional kWh, per kWh	2.065¢	2.002¢		
28	First 20,000 kWh, per kWh	2.725¢	2.622¢		
	All additional kWh, per kWh	2.648¢	2.552¢		
30	First 20,000 kWh, per kWh	2.912¢	2.880¢		
	All additional kWh, per kWh	2.523¢	2.490¢		
41	Winter, first 100 kWh/kW, per kWh	3.889¢	3.758¢		
	Winter, all additional kWh, per kWh	2.649¢	2.566¢		
	Summer, all kWh, per kWh	2.649¢	2.566¢		(R)

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

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	2.568¢	2.383¢	2.238¢	(R)
	Per kWh, Off-Peak	2.518¢	2.333¢	2.188¢	(R)

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

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November. 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	2.087¢	(R)
	For dusk to midnight operation, per kWh	2.087¢	
54	Per kWh	1.535¢	(R)

15	Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
	Mercury Vapor	7,000	76	$ 1.59	(R)
	Mercury Vapor	21,000	172	$ 3.61	
	Mercury Vapor	55,000	412	$ 8.64	
	High Pressure Sodium	5,800	31	$ 0.65	
	High Pressure Sodium	22,000	85	$ 1.78	
	High Pressure Sodium	50,000	176	$ 3.69	(R)

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

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

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$1.31	$2.97	$7.12	(R)
Vertical, per lamp	$1.31	$2.97		(R)

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

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.31			(R)
On 26-foot poles, vertical, per lamp	$1.31			
On 30-foot poles, horizontal, per lamp		$2.97		
On 30-foot poles, vertical, per lamp		$2.97		
On 33-foot poles, horizontal, per lamp			$7.12	(R)

(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	$1.31			(R)
On 26-foot poles, vertical, per lamp	$1.31			
On 30-foot poles, horizontal, per lamp		$2.97		
On 30-foot poles, vertical, per lamp		$2.97		
On 33-foot poles, horizontal, per lamp			$7.12	(R)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.52	(R)
LED	6,200	150 (comp)		$0.74	
LED	13,000	250 (comp)		$1.39	
LED	16,800	400 (comp)		$1.88	
High Pressure Sodium	5,800	70	31	$0.84	
High Pressure Sodium	9,500	100	44	$1.20	
High Pressure Sodium	16,000	150	64	$1.74	
High Pressure Sodium	22,000	200	85	$2.32	
High Pressure Sodium	27,500	250	115	$3.13	
High Pressure Sodium	50,000	400	176	$4.80	
Metal Halide	12,000	175	68	$1.85	
Metal Halide	19,500	250	94	$2.56	(R)

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.28	(R)
High Pressure Sodium	9,500	100	44	$0.39	
High Pressure Sodium	16,000	150	64	$0.57	
High Pressure Sodium	22,000	200	85	$0.76	
High Pressure Sodium	27,500	250	115	$1.02	
High Pressure Sodium	50,000	400	176	$1.56	
Metal Halide	9,000	100	39	$0.35	
Metal Halide	12,000	175	68	$0.60	
Metal Halide	19,500	250	94	$0.84	
Metal Halide	32,000	400	149	$1.32	
Metal Halide	107,800	1,000	354	$3.15	
Non-Listed Luminaire, per kWh			0.889¢		(R)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER REVENUES

Purpose

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

Applicable

To all Residential Consumers and Nonresidential Consumers.

Energy Charge

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

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	0.019¢			
		> 1000 kWh	0.027¢			(I)
5	Per kWh	0-1000 kWh	0.019¢			
		> 1000 kWh	0.027¢			(I)

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

		Secondary	**Primary**	**Transmission**	
23, 723	First 3,000 kWh, per kWh	0.023¢	0.022¢		(I)
	All additional kWh, per kWh	0.017¢	0.015¢		(I)
28, 728	First 20,000 kWh, per kWh	0.021¢	0.021¢		(I)
	All additional kWh, per kWh	0.020¢	0.019¢		(I)
30, 730	First 20,000 kWh, per kWh	0.023¢	0.022¢		(I)
	All additional kWh, per kWh	0.020¢	0.019¢		(I)
41, 741	Winter, first 100 kWh/kW, per kWh	0.030¢	0.029¢		(I)
	Winter, all additional kWh, per kWh	0.021¢	0.019¢		|
	Summer, all kWh, per kWh	0.021¢	0.019¢		(I)

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

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
47/48 Per kWh On-Peak	0.020¢	0.017¢	0.016¢	(I)
747/748 Per kWh, Off-Peak	0.020¢	0.017¢	0.016¢	(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, 752	For dusk to dawn operation, per kWh	0.016¢
	For dusk to midnight operation, per kWh	0.016¢
54,754	Per kWh	0.010¢

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**
	Mercury Vapor	7,000	76	$0.01
	Mercury Vapor	21,000	172	$0.03
	Mercury Vapor	55,000	412	$0.07
	High Pressure Sodium	5,800	31	$0.00
	High Pressure Sodium	22,000	85	$0.01
	High Pressure Sodium	50,000	176	$0.03

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

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

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
Horizontal, per lamp	$0.01	$0.02	$0.05
Vertical, per lamp	$0.01	$0.02	

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

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$0.01		
On 26-foot poles, vertical, per lamp	$0.01		
On 30-foot poles, horizontal, per lamp		$0.02	
On 30-foot poles, vertical, per lamp		$0.02	
On 33-foot poles, horizontal, per lamp			$0.05

(continued)

Energy Charge (continued)

Delivery Service Schedule No.

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

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$0.01		
On 26-foot poles, vertical, per lamp	$0.01		
On 30-foot poles, horizontal, per lamp		$0.02	
On 30-foot poles, vertical, per lamp		$0.02	
On 33-foot poles, horizontal, per lamp			$0.05

51, 751	**Types of Luminaire**	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
	LED	4,000	100 (comp)		$0.00	
	LED	6,200	150 (comp)		$0.01	
	LED	13,000	250 (comp)		$0.01	
	LED	16,800	400 (comp)		$0.01	
	High Pressure Sodium	5,800	70	31	$0.01	
	High Pressure Sodium	9,500	100	44	$0.01	
	High Pressure Sodium	16,000	150	64	$0.01	
	High Pressure Sodium	22,000	200	85	$0.02	
	High Pressure Sodium	27,500	250	115	$0.02	
	High Pressure Sodium	50,000	400	176	$0.04	(I)
	Metal Halide	12,000	175	68	$0.01	
	Metal Halide	19,500	250	94	$0.02	

53, 753	**Types of Luminaire**	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**
	High Pressure Sodium	5,800	70	31	$0.00
	High Pressure Sodium	9,500	100	44	$0.00
	High Pressure Sodium	16,000	150	64	$0.00
	High Pressure Sodium	22,000	200	85	$0.01
	High Pressure Sodium	27,500	250	115	$0.01
	High Pressure Sodium	50,000	400	176	$0.01
	Metal Halide	9,000	100	39	$0.00
	Metal Halide	12,000	175	68	$0.00
	Metal Halide	19,500	250	94	$0.01
	Metal Halide	32,000	400	149	$0.01
	Metal Halide	107,800	1,000	354	$0.02

Non-Listed Luminaire, per kWh 0.007¢

Docket No. UE 356
Exhibit PAC/304
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

April 2019

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, 2020

					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	517,792	5,416,910	$625,841	($20,908)	$604,933	$619,671	($20,908)	$598,763	($6,170)	-1.0%	($6,170)	-1.0%	1
2	**Total Residential**		517,792	5,416,910	$625,841	($20,908)	$604,933	$619,671	($20,908)	$598,763	($6,170)	-1.0%	($6,170)	-1.0%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	82,002	1,137,606	$126,606	($149)	$126,457	$125,369	($149)	$125,220	($1,237)	-1.0%	($1,237)	-1.0%	3
4	Gen. Svc. 31 - 200 kW	28	10,697	2,024,568	$186,146	($4,212)	$181,934	$183,897	($4,212)	$179,685	($2,249)	-1.2%	($2,249)	-1.2%	4
5	Gen. Svc. 201 - 999 kW	30	860	1,320,150	$107,693	($3,075)	$104,618	$106,280	($3,075)	$103,205	($1,413)	-1.3%	($1,413)	-1.4%	5
6	Large General Service >= 1,000 kW	48	196	3,358,471	$236,075	($19,427)	$216,648	$232,812	($19,427)	$213,385	($3,263)	-1.4%	($3,263)	-1.5%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	50,503	$5,702	($295)	$5,407	$5,656	($295)	$5,361	($46)	-1.4%	($46)	-1.5%	7
8	Agricultural Pumping Service	41	7,931	220,786	$25,751	($2,321)	$23,430	$25,509	($2,321)	$23,188	($242)	-0.9%	($242)	-1.0%	8
9	**Total Commercial & Industrial**		101,692	8,112,084	$687,973	($29,479)	$658,494	$679,523	($29,479)	$650,044	($8,450)	-1.2%	($8,450)	-1.3%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,215	8,880	$1,145	$161	$1,306	$1,137	$161	$1,298	($8)	-0.7%	($8)	-0.6%	10
11	Street Lighting Service	50	223	7,833	$875	$132	$1,007	$869	$132	$1,001	($6)	-0.7%	($6)	-0.6%	11
12	Street Lighting Service HPS	51	834	19,135	$3,372	$542	$3,914	$3,350	$542	$3,892	($22)	-0.7%	($22)	-0.6%	12
13	Street Lighting Service	52	35	990	$130	$16	$146	$129	$16	$145	($1)	-0.8%	($1)	-0.7%	13
14	Street Lighting Service	53	342	11,894	$751	$112	$863	$746	$112	$858	($5)	-0.7%	($5)	-0.6%	14
15	Recreational Field Lighting	54	104	1,383	$115	$17	$132	$114	$17	$131	($1)	-0.9%	($1)	-0.8%	15
16	**Total Public Street Lighting**		7,753	50,115	$6,388	$980	$7,368	$6,345	$980	$7,325	($43)	-0.7%	($43)	-0.6%	16
17	**Total Sales before Emp. Disc. & AGA**		627,237	13,579,109	$1,320,202	($49,407)	$1,270,795	$1,305,539	($49,407)	$1,256,132	($14,663)	-1.1%	($14,663)	-1.2%	17
18	Employee Discount				($486)	$18	($468)	($481)	$18	($463)	$5		$5		18
19	**Total Sales with Emp. Disc**		627,237	13,579,109	$1,319,716	($49,389)	$1,270,327	$1,305,058	($49,389)	$1,255,669	($14,658)	-1.1%	($14,658)	-1.2%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		627,237	13,579,109	$1,322,155	($49,389)	$1,272,766	$1,307,497	($49,389)	$1,258,108	($14,658)	-1.1%	($14,658)	-1.2%	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	$19.75	$19.64	($0.11)	-0.56%
200	$29.01	$28.79	($0.22)	-0.76%
300	$38.27	$37.95	($0.32)	-0.84%
400	$47.53	$47.11	($0.42)	-0.88%
500	$56.81	$56.27	($0.54)	-0.95%
600	$66.08	$65.43	($0.65)	-0.98%
700	$75.34	$74.59	($0.75)	-1.00%
800	$84.61	$83.75	($0.86)	-1.02%
850	**$89.24**	**$88.33**	**($0.91)**	**-1.02%**
900	$93.86	$92.90	($0.96)	-1.02%
1,000	$103.14	$102.07	($1.07)	-1.04%
1,100	$115.57	$114.35	($1.22)	-1.06%
1,200	$127.98	$126.62	($1.36)	-1.06%
1,300	$140.42	$138.91	($1.51)	-1.08%
1,400	$152.84	$151.18	($1.66)	-1.09%
1,500	$165.27	$163.46	($1.81)	-1.10%
1,600	$177.69	$175.75	($1.94)	-1.09%
2,000	$227.39	$224.86	($2.53)	-1.11%
3,000	$351.65	$347.65	($4.00)	-1.14%
4,000	$475.90	$470.44	($5.46)	-1.15%
5,000	$600.16	$593.24	($6.92)	-1.15%

* 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

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$70	$79	$69	$78	-0.84%	-0.75%
	750	$96	$105	$95	$104	-0.92%	-0.85%
	1,000	$122	$131	$121	$130	-0.98%	-0.90%
	1,500	$174	$183	$172	$181	-1.02%	-0.97%
10	1,000	$122	$131	$121	$130	-0.98%	-0.90%
	2,000	$226	$235	$224	$232	-1.05%	-1.01%
	3,000	$330	$339	$326	$335	-1.08%	-1.05%
	4,000	$417	$426	$413	$422	-1.06%	-1.04%
20	4,000	$444	$453	$440	$449	-1.00%	-0.98%
	6,000	$619	$628	$613	$622	-1.00%	-0.98%
	8,000	$794	$802	$786	$794	-1.00%	-0.99%
	10,000	$968	$977	$958	$967	-1.00%	-0.99%
30	9,000	$935	$944	$926	$935	-0.94%	-0.93%
	12,000	$1,197	$1,205	$1,185	$1,194	-0.96%	-0.95%
	15,000	$1,459	$1,467	$1,445	$1,453	-0.96%	-0.96%
	18,000	$1,721	$1,729	$1,704	$1,713	-0.97%	-0.97%

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

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

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$68	$77	$68	$77	-0.83%	-0.74%
	750	$94	$103	$93	$102	-0.92%	-0.84%
	1,000	$119	$128	$118	$127	-0.96%	-0.89%
	1,500	$170	$178	$168	$177	-1.01%	-0.96%
10	1,000	$119	$128	$118	$127	-0.96%	-0.89%
	2,000	$220	$229	$218	$227	-1.04%	-1.00%
	3,000	$321	$330	$318	$327	-1.07%	-1.04%
	4,000	$406	$415	$402	$411	-1.06%	-1.03%
20	4,000	$433	$441	$428	$437	-0.99%	-0.97%
	6,000	$603	$611	$597	$605	-0.99%	-0.98%
	8,000	$772	$781	$765	$774	-1.00%	-0.99%
	10,000	$942	$951	$933	$942	-1.00%	-0.99%
30	9,000	$910	$919	$902	$910	-0.94%	-0.93%
	12,000	$1,165	$1,174	$1,154	$1,163	-0.95%	-0.95%
	15,000	$1,420	$1,429	$1,406	$1,415	-0.96%	-0.96%
	18,000	$1,675	$1,683	$1,658	$1,667	-0.97%	-0.97%

* 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	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$341	$338	-1.01%
	4,500	$450	$444	-1.16%
	7,500	$666	$658	-1.30%
31	6,200	$686	$678	-1.04%
	9,300	$910	$899	-1.18%
	15,500	$1,357	$1,340	-1.32%
40	8,000	$879	$870	-1.05%
	12,000	$1,168	$1,154	-1.18%
	20,000	$1,746	$1,723	-1.32%
60	12,000	$1,311	$1,297	-1.06%
	18,000	$1,744	$1,723	-1.19%
	30,000	$2,594	$2,559	-1.32%
80	16,000	$1,736	$1,717	-1.06%
	24,000	$2,307	$2,279	-1.19%
	40,000	$3,435	$3,389	-1.33%
100	20,000	$2,161	$2,138	-1.07%
	30,000	$2,866	$2,832	-1.20%
	50,000	$4,276	$4,219	-1.33%
200	40,000	$4,228	$4,183	-1.08%
	60,000	$5,638	$5,570	-1.21%
	100,000	$8,459	$8,346	-1.33%

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

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$437	$432	-1.14%
	6,000	$535	$528	-1.25%
	7,500	$634	$625	-1.32%
31	9,300	$876	$866	-1.18%
	12,400	$1,080	$1,066	-1.28%
	15,500	$1,283	$1,266	-1.34%
40	12,000	$1,123	$1,110	-1.19%
	16,000	$1,386	$1,368	-1.28%
	20,000	$1,648	$1,626	-1.35%
60	18,000	$1,675	$1,655	-1.20%
	24,000	$2,062	$2,035	-1.29%
	30,000	$2,446	$2,413	-1.36%
80	24,000	$2,212	$2,186	-1.20%
	32,000	$2,724	$2,689	-1.30%
	40,000	$3,236	$3,192	-1.36%
100	30,000	$2,747	$2,714	-1.21%
	40,000	$3,387	$3,343	-1.30%
	50,000	$4,027	$3,972	-1.37%
200	60,000	$5,383	$5,317	-1.22%
	80,000	$6,663	$6,575	-1.32%
	100,000	$7,943	$7,833	-1.38%

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

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,600	$2,575	-0.95%
	30,000	$3,167	$3,132	-1.12%
	50,000	$4,302	$4,245	-1.33%
200	40,000	$4,555	$4,509	-1.02%
	60,000	$5,690	$5,622	-1.19%
	100,000	$7,960	$7,849	-1.40%
300	60,000	$6,681	$6,613	-1.02%
	90,000	$8,383	$8,283	-1.20%
	150,000	$11,788	$11,623	-1.40%
400	80,000	$8,688	$8,598	-1.03%
	120,000	$10,958	$10,825	-1.21%
	200,000	$15,498	$15,279	-1.42%
500	100,000	$10,726	$10,615	-1.04%
	150,000	$13,563	$13,398	-1.22%
	250,000	$19,238	$18,965	-1.42%
600	120,000	$12,764	$12,631	-1.04%
	180,000	$16,169	$15,971	-1.22%
	300,000	$22,979	$22,651	-1.43%
800	160,000	$16,840	$16,664	-1.05%
	240,000	$21,380	$21,117	-1.23%
	400,000	$30,460	$30,024	-1.43%
1000	200,000	$20,916	$20,697	-1.05%
	300,000	$26,591	$26,263	-1.23%
	500,000	$37,941	$37,397	-1.43%

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

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$3,104	$3,069	-1.13%
	40,000	$3,661	$3,615	-1.25%
	50,000	$4,217	$4,160	-1.34%
200	60,000	$5,580	$5,513	-1.20%
	80,000	$6,692	$6,604	-1.32%
	100,000	$7,805	$7,695	-1.40%
300	90,000	$8,216	$8,117	-1.20%
	120,000	$9,884	$9,753	-1.32%
	150,000	$11,553	$11,390	-1.41%
400	120,000	$10,756	$10,626	-1.21%
	160,000	$12,981	$12,808	-1.33%
	200,000	$15,205	$14,990	-1.42%
500	150,000	$13,309	$13,147	-1.22%
	200,000	$16,090	$15,874	-1.34%
	250,000	$18,871	$18,602	-1.42%
600	180,000	$15,862	$15,668	-1.22%
	240,000	$19,199	$18,941	-1.34%
	300,000	$22,536	$22,214	-1.43%
800	240,000	$20,968	$20,710	-1.23%
	320,000	$25,417	$25,075	-1.35%
	400,000	$29,867	$29,439	-1.43%
1000	300,000	$26,074	$25,752	-1.23%
	400,000	$31,636	$31,208	-1.35%
	500,000	$37,197	$36,664	-1.43%

* 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	$183	$212	$155	$181	$209	$155	-1.23%	-1.31%	0.00%
	3,000	$275	$303	$155	$271	$299	$155	-1.23%	-1.29%	0.00%
	5,000	$458	$486	$155	$452	$480	$155	-1.23%	-1.26%	0.00%
Three Phase										
20	4,000	$366	$423	$309	$362	$418	$309	-1.23%	-1.31%	0.00%
	6,000	$549	$606	$309	$542	$598	$309	-1.23%	-1.29%	0.00%
	10,000	$915	$972	$309	$904	$960	$309	-1.23%	-1.26%	0.00%
100	20,000	$1,830	$2,116	$1,349	$1,808	$2,088	$1,349	-1.23%	-1.31%	0.00%
	30,000	$2,746	$3,031	$1,349	$2,712	$2,992	$1,349	-1.23%	-1.29%	0.00%
	50,000	$4,576	$4,862	$1,349	$4,520	$4,800	$1,349	-1.23%	-1.26%	0.00%
300	60,000	$5,491	$6,349	$3,409	$5,424	$6,265	$3,409	-1.23%	-1.31%	0.00%
	90,000	$8,237	$9,094	$3,409	$8,136	$8,977	$3,409	-1.23%	-1.29%	0.00%
	150,000	$13,729	$14,586	$3,409	$13,560	$14,401	$3,409	-1.23%	-1.26%	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	$265	$293	$155	$262	$289	$155	-1.25%	-1.31%	0.00%
	4,000	$354	$382	$155	$349	$377	$155	-1.25%	-1.30%	0.00%
	5,000	$442	$470	$155	$437	$464	$155	-1.25%	-1.29%	0.00%
Three Phase										
20	6,000	$531	$586	$309	$524	$578	$309	-1.25%	-1.31%	0.00%
	8,000	$708	$763	$309	$699	$753	$309	-1.25%	-1.30%	0.00%
	10,000	$885	$940	$309	$874	$928	$309	-1.25%	-1.29%	0.00%
100	30,000	$2,654	$2,931	$1,339	$2,621	$2,892	$1,339	-1.25%	-1.31%	0.00%
	40,000	$3,539	$3,815	$1,339	$3,495	$3,766	$1,339	-1.25%	-1.30%	0.00%
	50,000	$4,423	$4,700	$1,339	$4,368	$4,639	$1,339	-1.25%	-1.29%	0.00%
300	90,000	$7,962	$8,792	$3,399	$7,863	$8,676	$3,399	-1.25%	-1.31%	0.00%
	120,000	$10,616	$11,446	$3,399	$10,484	$11,297	$3,399	-1.25%	-1.30%	0.00%
	150,000	$13,270	$14,100	$3,399	$13,104	$13,918	$3,399	-1.25%	-1.29%	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		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$26,005	$25,681	-1.25%
	500,000	$36,919	$36,378	-1.46%
	650,000	$45,104	$44,401	-1.56%
2,000	600,000	$51,578	$50,929	-1.26%
	1,000,000	$71,155	$70,074	-1.52%
	1,300,000	$86,701	$85,295	-1.62%
6,000	1,800,000	$149,501	$147,554	-1.30%
	3,000,000	$211,683	$208,438	-1.53%
	3,900,000	$258,320	$254,102	-1.63%
12,000	3,600,000	$297,677	$293,784	-1.31%
	6,000,000	$422,042	$415,553	-1.54%
	7,800,000	$515,315	$506,880	-1.64%

Notes:

On-Peak kWh	64.46%
Off-Peak kWh	35.54%

* 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 Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	300,000	$24,554	$24,251	-1.23%
	500,000	$34,649	$34,145	-1.46%
	650,000	$42,221	$41,565	-1.55%
2,000	600,000	$48,634	$48,028	-1.25%
	1,000,000	$66,575	$65,566	-1.52%
	1,300,000	$80,894	$79,581	-1.62%
6,000	1,800,000	$140,266	$138,449	-1.30%
	3,000,000	$197,540	$194,512	-1.53%
	3,900,000	$240,496	$236,559	-1.64%
12,000	3,600,000	$279,177	$275,543	-1.30%
	6,000,000	$393,726	$387,669	-1.54%
	7,800,000	$479,637	$471,764	-1.64%

Notes:

On-Peak kWh	61.37%
Off-Peak kWh	38.63%

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

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

kW Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	500,000	$34,344	$33,870	-1.38%
	650,000	$41,366	$40,750	-1.49%
2,000	1,000,000	$65,552	$64,604	-1.45%
	1,300,000	$78,772	$77,540	-1.56%
6,000	3,000,000	$194,645	$191,803	-1.46%
	3,900,000	$234,305	$230,610	-1.58%
12,000	6,000,000	$387,143	$381,457	-1.47%
	7,800,000	$466,462	$459,071	-1.58%
50,000	25,000,000	$1,606,294	$1,582,604	-1.47%
	32,500,000	$1,936,791	$1,905,994	-1.59%

Notes:

On-Peak kWh	56.82%
Off-Peak kWh	43.18%

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