PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 14, 2020

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

Re: Advice No. 20-002/UE 375—PacifiCorp's 2021 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, 2021.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2021 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/402. This tariff filing is supported by testimony and exhibits from the following witnesses:

- David G. Webb, Manager, Net Power Costs
- Ramon J. Mitchell, Organized Market Analyst
- Dana M. Ralston, Senior Vice President, Thermal Generation and Mining
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

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

PacifiCorp will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—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 628,000 customers, and would result in an overall annual rate decrease of approximately $49.2 million or 3.7 percent. Residential customers using 900 kilowatt-hours per month would see a monthly bill decrease of $2.95 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
Senior Attorney
825 NE Multnomah Street, Suite 2000
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 2020 TAM proceeding, docket UE 356. Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

cc: UE 356 Service List

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Advice No. 20-002/UE 375—PacifiCorp's 2021 Transition Adjustment Mechanism** on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

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UE 356

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Dated this 14th day of February, 2020.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 375
Exhibit PAC/100
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

REDACTED
Direct Testimony of David G. Webb

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/101—Oregon-Allocated Net Power Costs

Exhibit PAC/102—Net Power Costs Report

Confidential Exhibit PAC/103—Update to Renewable Energy Production Tax Credits

Exhibit PAC/104—Step Log Change

Exhibit PAC/105—January 15, 2020 Notice Letter

Exhibit PAC/106—List of Expected or Known Contract Updates

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is David G. Webb and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Please describe your education and professional experience.

A. I received a Master of Accountancy degree from Southern Utah University in 1999 and a Bachelor of Science degree in Business Management from Brigham Young University in 1994. I am a Certified Public Accountant licensed in the state of Nevada. I have been employed by PacifiCorp since 2005 and have held various positions in the regulation, finance, fuels, and mining departments. I assumed my current role managing the net power cost group in 2019.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony in Utah.

II. PURPOSE OF TESTIMONY

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

A. I present the Company's proposed 2021 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing;
- Provides an update on a number of provisions from docket UE 356 (2020 TAM);
- Defines NPC and describes the NPC decrease in the 2021 TAM compared to the final NPC in the 2020 TAM;
- Describes the major cost drivers in the 2021 TAM;

- Describes modeling changes the Company is proposing to increase the accuracy of the TAM;
- Provides the details on the calculation of the Consumer Opt Out Charge for those customers electing the five-year direct access program;
- 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 2021 TAM.

A. Three additional Company witnesses provide testimony supporting the Company's filing. Mr. Ramon J. Mitchell, Organized Market Analyst, presents the Company's forecast of its Energy Imbalance Market (EIM) inter-regional transfer benefits and EIM greenhouse gas (GHG) benefits for calendar year 2021. Mr. Dana M. Ralston, Senior Vice President, Thermal Generation and Mining, provides testimony supporting the coal fuel costs included in the 2021 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.

III. SUMMARY OF PACIFICORP'S 2021 TAM FILING

Q. Please provide background on PacifiCorp's 2021 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 2021 TAM also includes test period forecasts for: (1) incremental benefits and costs related to the Company's participation in the EIM with the California Independent System Operator Corporation (CAISO); and (2) renewable energy production tax credits (PTC). The Company is filing the 2021 TAM concurrently with a general rate case, docket UE 374 (2021 General Rate Case).

As shown in Exhibit PAC/101, the 2021 TAM results in a decrease to Oregon rates of approximately $49.2 million, which includes a decrease to Oregon-allocated NPC of approximately $13.6 million and an increase in PTCs (decrease to rates) of approximately $39 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 2021 TAM results in an overall average rate decrease of approximately 3.7 percent.

Q. What are the total-company NPC in the TAM for calendar year 2021?

A. The forecasted total-company NPC for calendar year 2021 are approximately $1.401 billion.[1] This is approximately $40.4 million lower than the forecast NPC of approximately $1.441 billion in the 2020 TAM. Details of total-company NPC for 2021 are provided in Exhibit PAC/102.

Q. Does the proposed rate decrease for the 2021 TAM reflect changes in Oregon load since the 2020 TAM?

A. Yes. The 2021 load forecast used in the Company's calculation of NPC reflects an increase in Oregon load compared to the 2020 forecast loads in the 2020 TAM. Due to the increase in Oregon load, the Company anticipates it will collect approximately $3.4 million more than what was approved in the 2020 TAM.

Q. How are Other Revenues for certain items related to NPC treated in the 2021 TAM?

A. As explained by Ms. Ridenour, as part of the Company's 2021 General Rate Case, Schedule 205 rates are proposed to go to zero as the present adjustments will now be

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

incorporated into base rates. Schedule 205 will be updated for incremental changes in Other Revenues in future TAMs.

Q. Please explain how the EIM inter-regional and GHG benefits are treated in the 2021 TAM.

A. PacifiCorp's initial filing includes a forecast of both the inter-regional benefits and GHG benefits from participation in the EIM. The expected incremental inter-regional EIM benefits relative to the optimized NPC modeled by the Generation and Regulation Initiative Decision Tools (GRID) model are reflected as a reduction to the NPC forecast. The total-company inter-regional EIM benefits included in the 2021 TAM are [redacted], a decrease of [redacted] in benefits from the amount stipulated to in the 2020 TAM. The GHG benefit is [redacted], a [redacted] increase from the 2020 TAM. Mr. Mitchell provides additional detail regarding the EIM benefits forecast for the test period in his direct testimony.

Q. Please explain how the non-NPC EIM costs are treated in the 2021 TAM.

A. The non-NPC EIM costs are included in the 2021 General Rate Case and are not included in the 2021 TAM.[2]

IV. COMPLIANCE WITH 2020 TAM ORDER

Q. Were there any requirements agreed to as part of the 2020 TAM stipulation that impacted the 2021 TAM?

A. Yes. In Order 19-351, the Commission adopted the stipulation reached between the

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[2] *In the matter of PacifiCorp d/b/a Pacific Power's 2019 Transition Adjustment Mechanism*, Docket UE 339, Order No 18-421 (Oct. 26, 2018) (accepting PacifiCorp's commitment to include EIM costs in its next General Rate Case).

parties.[3] PacifiCorp agreed to the following:

- Stipulated repowering and Energy Vision 2020 wind plant capacity factors from the 2020 TAM and to carry these capacity factors forward until 2024 (2025 TAM);
- A workshop to discuss Bridger Coal Company depreciation issues;
- A workshop to discuss modeling EIM benefits prior to filing the 2021 TAM; and
- A workshop on PacifiCorp's natural gas trading activities.

Q. Has PacifiCorp complied with the requirements in the stipulation?

A. Yes. PacifiCorp has used the agreed-upon capacity factors in the 2021 TAM. Additionally, the Company held the Bridger Coal Company workshop on September 23, 2019. PacifiCorp also held a workshop on both EIM benefits and natural gas trading activities on January 30, 2020.

Q. Were there any additional requirements in the Commission order in the 2020 TAM?[4]

A. Yes. Besides adopting the stipulation the Commission set three additional requirements. PacifiCorp was directed to do the following:

- Update and expand its PTC calculation in the 2021 TAM;
- Include an explanation of the wholesales sales components and the multi-year trends; and
- Include testimony in the 2021 TAM regarding Jim Bridger fueling and participate in a Commission workshop after filing the 2021 TAM.

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[3] *See In the matter of PacifiCorp dba Pacific Power's 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351 (Oct. 30, 2019).

[4] Order No. 20-023 amending Order No. 19-351.

My testimony addresses the expanded PTC calculation, wholesale sales components and multi-year trends below. Mr. Ralston's testimony addresses the Jim Bridger fueling.

V. PRODUCTION TAX CREDITS

Q. Please describe the treatment of renewable energy PTCs in the 2021 TAM.

A. The 2021 TAM includes changes in the projected PTC amounts. Confidential Exhibit PAC/103 shows the forecast level of PTCs for 2021 compared to the level of PTCs established in the 2020 TAM. The forecast of Oregon-allocated PTCs for the 2021 test period is approximately $64.6 million, which is higher than the $25.6 million included in the 2020 TAM, resulting in a decrease to the 2021 TAM of $39 million. The increase in PTCs is due to the 2020 repowered wind projects and new wind projects collecting PTCs for a full calendar year of production.

Q. How are PTCs calculated for the 2021 TAM?

A. The renewable energy PTC provides a federal income tax credit for the first 10 years of a renewable energy facility's operation. The PTC is calculated by multiplying the qualifying generation by the current PTC rate of 2.5 cents per kilowatt-hour and then grossing-up for taxes.

Q. Please describe the capacity, capacity factors, generation and PTCs for the wind projects in the 2021 TAM.

A. As seen in Confidential Figure 1 below, on a total-company basis, the total-company owned wind capacity is 2,155 megawatts (MW). Total forecast generation on a total-company basis is 7,490,910 megawatt-hours (MWh). The total tax-adjusted PTCs on an Oregon-allocated basis are $64.6 million.

Confidential Figure 1
Company-Owned Wind Projects Generation and PTC Data

	Total Company				Oregon Allocated		
Plant Name	PTC Value	LGIA Capacity (MW)	LGIA Capacity Factor	Generation (MWH)	Factors CY 2021	CY 2021 Initial Filing	Revenue Requirement *(See Note 1)*
Glenrock	[redacted]	99.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Glenrock III	[redacted]	39.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Goodnoe Hills	[redacted]	94.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
High Plains Wind	[redacted]	99.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Leaning Juniper 1	[redacted]	100.5	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Marengo	[redacted]	156.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Marengo II	[redacted]	78.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
McFadden Ridge	[redacted]	28.5	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Seven Mile	[redacted]	99.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Seven Mile II	[redacted]	19.5	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Dunlap I Wind	[redacted]	111.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Foote Creek I Wind	[redacted]	41.4	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Pryor Mountain Wind	[redacted]	240.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Cedar Springs Wind II	[redacted]	200.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Ekola Flats Wind	[redacted]	250.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
TB Flats Wind	[redacted]	250.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
TB Flats Wind II	[redacted]	250.0	[redacted]	[redacted]	26.023%	[redacted]	[redacted]
Total Production Tax Credit	$ 187,272,741	2,154.9		7,490,910		$ 48,733,297	$ 64,621,536

Note 1 - Revenue Requirement represents the PTC amount grossed up for the tax rate.

Q. How are the benefits and costs of the Foote Creek I, Dunlap, and Glenrock III repowering projects included in rates?

A. The NPC and PTC benefits associated with these plants and all other repowered wind plants are included in the 2021 TAM. The costs associated with repowering Glenrock III (39 MW) and Dunlap (111 MW) were included in PacifiCorp's 2020 Renewable Adjustment Clause (RAC).[5] The Foote Creek I (41.4 MW) investment is included in the 2021 General Rate Case.[6]

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[5] *See In the matter of PacifiCorp d/b/a Pacific Power, 2020 Renewable Adjustment Clause*, Docket No. UE-369, Advice No. 19-020 (Nov. 20, 2019).

[6] *See In the matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Advice No. 20-001 (Feb. 14, 2020).

Q. Please describe the Energy Vision 2020 Wind Projects and other new wind projects and how they are treated in the 2021 TAM?

A. The Energy Vision 2020 Wind Projects include 1,150 MW of new wind assets at TB Flats, Cedar Springs II, Ekola Flats, and a power purchase agreement (PPA), Cedar Springs I. Associated with the Energy Vision 2020 Wind Projects is 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. In addition to the Energy Vision 2020 Projects, the TAM includes two other wind projects, the 240 MW Pryor Mountain wind project and the 133.3 MW Cedar Springs III PPA. The NPC and PTC benefits of all new wind projects are included in the 2021 TAM. PacifiCorp is seeking recovery of the PacifiCorp-owned assets in the 2021 General Rate Case.

VI. 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.[7]

Q. Please explain how PacifiCorp calculates NPC.

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

Q. 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 2021 TAM?

A. No. PacifiCorp used the same version of the GRID model in the 2021 TAM that it used in the 2020 TAM subject to the update of the Official Forward Price Curve (OFPC) hourly scalars and the flexible reserve study from the 2019 Integrated Resource Plan (IRP).

Q. What inputs were updated for this filing?

A. The Company updated all inputs to the 2021 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.

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

Q. What is the date of the OFPC the Company used in this filing?

A. PacifiCorp's filing uses an OFPC dated December 31, 2019.

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

A. Yes. In accordance with the current 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.

VII. DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2020 TAM.

A. The decrease in NPC is driven by a reduction in purchase power expense, lower coal fuel expense, and increasing renewable generation. The decrease is partially offset by a reduction in wholesale sales revenue, an increase in natural gas fuel expenses and wheeling expense. Figure 2 illustrates the change in total-company NPC by category from the NPC baseline in the 2020 TAM.

Figure 2
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2020	**$1,441**	**$24.12**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	148	
Purchased Power Expense	(115)	
Coal Fuel Expense	(79)	
Natural Gas Fuel Expense	4	
Wheeling and Other Expense	8	
Total Increase/(Decrease) to NPC	**(40)**	
OR TAM 2021	**$1,401**	**$23.14**

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower sales volumes. Total wholesale sales revenue is $148.3 million lower than the 2020 TAM with most of the reduction coming from market transactions (represented in GRID as short-term firm and system balancing sales). Market sales transactions in the 2021 TAM are 5,493 gigawatt-hours (GWh) lower than in the 2020 TAM. The reduction is partially offset by the higher average market prices during 2021. The average market price of wholesale sales in the 2021 TAM is $32.64/MWh, while in the 2020 TAM the average market price was $30.41/MWh, a seven percent increase.

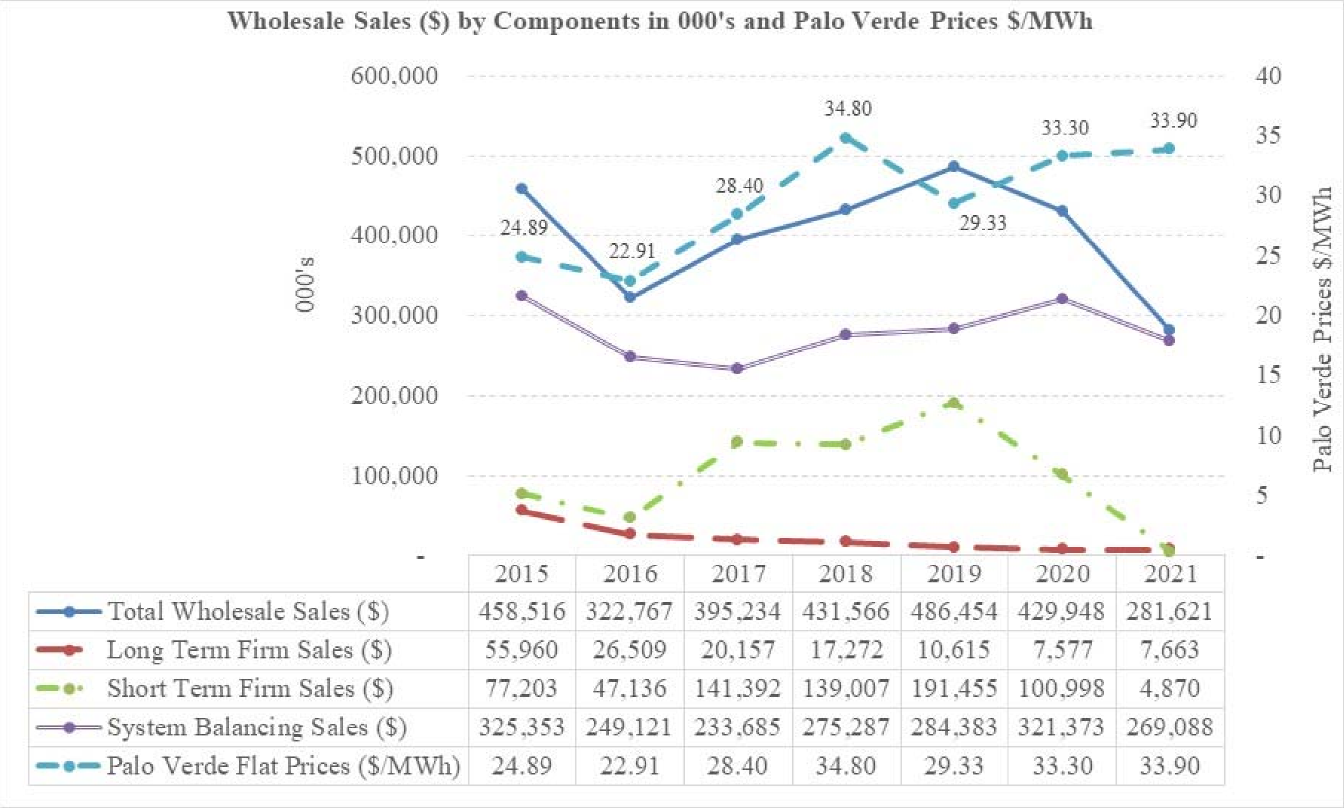
Q. What are the components of wholesale sales in NPC?

A. In NPC, wholesale sales represent the wholesale revenue the Company receives from various power sales activities. Long-term firm sales, short-term firm sales and system balancing sales comprise the total-company wholesale revenues. Long-term firm sales are wholesale sales contracts longer than a one-year period. Short-term firm sales are wholesale sales contracts shorter than a one-year period. Both long-term and short-term firm sales are executed transactions during the forecast period on specific terms. System balancing sales are GRID model driven market transactions, which are used in the model to economically balance load and resources in the forecast period.

Q. Please explain the wholesale sales trend over the past several years.

A. The following chart shows the forecasted wholesale sales in the TAM by each component from 2015 to 2021 on a total-company basis. Total wholesale sales fluctuate between $322.8 million and $486.5 million. The average annual wholesale sales revenue from 2015 to 2020 is $420.8 million. The year 2016 is a relatively low year with $322.8 million wholesales sales revenues, approximately $98 million lower than the six-year average. Long-term firm sales revenue has steadily decreased from $56 million to $7.6 million over six years, due to expiring wholesale sales contracts. Short-term firm sales revenue has fluctuated year over year with the lowest amount in 2016, and on average short-term firm sales revenue is around $116.2 million. The lowest year of short-term firm sales revenue is $47.1 million in 2016, about $69.1 million lower than the six-year average. System balancing sales revenue stays in a relatively stable range, varying between $233.7 million and $325.4 million. The annual average system balancing sales revenue over the period of 2015 to 2020 is $281.5 million.

Figure 3



	2015	2016	2017	2018	2019	2020	2021
Total Wholesale Sales ($)	458,516	322,767	395,234	431,566	486,454	429,948	281,621
Long Term Firm Sales ($)	55,960	26,509	20,157	17,272	10,615	7,577	7,663
Short Term Firm Sales ($)	77,203	47,136	141,392	139,007	191,455	100,998	4,870
System Balancing Sales ($)	325,353	249,121	233,685	275,287	284,383	321,373	269,088
Palo Verde Flat Prices ($/MWh)	24.89	22.91	28.40	34.80	29.33	33.30	33.90

Q. Why has long-term firm wholesale revenue decreased over the last six years?

A. In the past six years, several long-term wholesale sales contracts have expired or have been terminated, including contracts with the following counterparties:

- Los Angeles Department of Water and Power (2016);
- Utah Municipal Power Agency (2017);
- Black Hills Power annual fixed payment (2018); and
- Bonneville Power Administration wind sales contract (2019).

Q. Why were short-term firm sales lower in 2016 compared to other years during the period of 2015 to 2020?

A. Short-term firm sales are market transactions executed within various market hubs to balance the Company's expected resources and loads as well as manage price volatility for the future period. Short-term firm sales included in the TAM represent a snapshot at the time of the filing of actual transactions that have been entered into for the test period. Annual TAM filings have included short-term firm sales from several market hubs. Figure 4 shows that the majority of the Company's short-term firm sales are transacted at the Palo Verde (PV) market hub with transactions at other hubs such as California-Oregon Border (COB), Four Corners and Mid-Columbia far behind. The reduction in short-term firm transactions in 2016 is mainly because of the relatively low PV power prices of $22.91/MWh compared to higher prices at PV in other years.

Figure 4

TAM Short Term Firm % by Market Hub

Year	COB	Four Corners	Mead	Mid Columbia	Mona	Palo Verde
2015						100%
2016	16%	0%	2%	2%	2%	78%
2017	0%	4%	2%	0%	0%	94%
2018	1%	3%	0%	0%	0%	95%
2019	3%	5%	1%	0%	0%	91%
2020	2%	4%	5%	0%	2%	86%

Q. How does each component of wholesale sales revenue in the 2021 TAM compare to the historical period?

A. In the 2021 TAM, long-term firm wholesale sales revenue remains flat from the 2020 TAM. The system balancing sales revenue only changes slightly as compared to the system balancing sales from the historical period.

The short-term firm revenue in this filing is at a lower level than what is reflected in the final update of the prior TAM proceedings. This is because the short-term firm sales are the actual short-term firm transactions, or hedges, the Company has entered into for the test period. The Company hedges on a rolling 36-month horizon but the majority of the trading activity is for the next 12 months. Therefore, the final TAM filed in November will have larger volumes of short-term firm sales than the initial TAM filing due to the timing. The volumes of short-term firm sales for the test period will typically increase with each subsequent TAM update until the final TAM filing.

Q. Why did purchased power expense decrease?

A. The decrease in purchased power expense is due to lower market purchase prices and several lower-cost long-term contracts starting to deliver power for a full year. The average price of the long-term contracts included in the 2021 TAM is $42.74/MWh, compared to the average price of long-term contracts in the 2020 TAM of $75.34/MWh. Market purchases (represented in GRID as short-term firm and system balancing purchases) in the current case have an average price of $17.73/MWh, while the 2020 TAM was an average price of $22.12/MWh.

The total expense for power purchased from Qualifying Facilities (QF) decreased by $2.4 million (total-company) with a small increase in the generation volume compared to the 2020 TAM. The reduction is attributed to the expiration of one legacy QF contract with a price of $175.35/MWh and the QF's subsequent renewal at the much lower price of $29.09/MWh.

No new QFs are forecast to come online in the 2021 TAM forecast period. In subsequent updates, the Company will update the NPC study as new information becomes available per the TAM Guidelines and apply the contract delay rate to new QF's expected commercial operation date in the updates.

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

A. Total coal fuel expense is $79.4 million lower than the 2020 TAM due to the lower coal generation volume at the Company coal plants. The average coal prices are $0.83/MWh higher than the prices in the 2020 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 period in his direct testimony.

Q. Please discuss the change in natural gas fuel expense compared to the 2020 TAM.

A. Natural gas fuel expense in the 2021 TAM is $4.3 million higher than the natural gas fuel expense in the 2020 TAM. The higher natural gas fuel expense in this TAM is due to higher natural gas market prices. The average cost of natural gas generation increased from $19.36/MWh in the 2020 TAM to $20.49/MWh in the current proceeding, a six percent increase. The increase is partially offset by the lower natural gas generation volume. Generation from natural gas plants in the 2021 TAM is 666 GWh less than the 2020 TAM, a four percent decrease.

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

A. Expenses in this category are higher due to the inclusion of the CAISO nodal pricing model expense at $8 million (total-company).

Q. How does the forecast wind generation compare to the 2020 TAM.

A. The new Company-owned wind projects are in production during 2021 which increased owned wind generation by 4,225 GWh, almost double the amount in the 2020 TAM.

Q. How are Jim Bridger Units 3 and 4 modeled in the 2021 TAM?

A. In PacifiCorp's 2021 TAM, the minimum operation levels of Jim Bridger Units 3 and 4 are updated to be consistent with the current operational level after installation of environmental upgrades. Selective catalytic reduction systems (SCR) were placed in operation in November 2015 for Unit 3, and November 2016 for Unit 4. PacifiCorp is seeking recovery of the environmental upgrade costs in the concurrently filed 2021 General Rate Case. In prior TAMs the Company agreed not to update the minimum operating levels of Jim Bridger Units 3 and 4 to reflect the fact that the SCRs had not been included in base rates.

Q. What updates are expected in the Company's resource portfolio relative to the 2020 TAM?

A. The Company updated minimum operation levels for several thermal plants. The impacts are included in Step 3 of Exhibit PAC/104, the Step Log.

Q. How is Naughton Unit 3 treated in the 2021 TAM?

A. Naughton Unit 3 will convert from a coal-fired resource to a natural gas resource in 2020, consistent with the 2019 IRP preferred portfolio. This conversion reduced NPC by $624,000, see Step 6 of Exhibit PAC/104, the Step Log.

Q. Does the Company model coal economic cycling in the 2021 TAM?

A. Yes. In the 2021 TAM, the Company is following the same logic for economic coal cycling that was used in the 2020 TAM which allows Hunter Units 1 and 2 to cycle economically during the cycling period from February 1 to May 31. Cholla 4 will close at the end of the 2020 so it is not part of the generation profile in the 2021 TAM.

Q. What is the impact of the economic cycling to the 2021 TAM?

A. The economic cycling of coal plants reduced NPC by approximately $42,000 in the 2021 TAM.

Q. Was the Day Ahead/Real Time (DA/RT) adjustment calculated in a manner that is consistent with how it was calculated in the 2020 TAM?

A. Yes. The DA/RT adjustment calculated in this filing was calculated with the same methodology that was used in the 2020 TAM.

Q. What is the impact of the DA/RT adjustment to the 2021 TAM?

A. The DA/RT adjustment in the 2021 TAM is approximately $11.3 million.

Q. What is the purpose of the DA/RT adjustment?

A. The DA/RT adjustment is used to better reflect system balancing costs that are not fully captured in the GRID model. This adjustment indicates a deviation of actual market prices available to the Company in real operations from the historical monthly market prices. The price volatility is related to the market conditions in the period that the Company experienced at the time when making day ahead and real time transactions. The DA/RT costs are the result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

Q. Did PacifiCorp make any changes to improve the accuracy of its NPC modeling since the 2020 TAM?

A. Yes. The Company's regulating reserve requirements are now based on the 2019

Flexible Reserve Study that was included in the 2019 IRP.[8] Additionally, OFPC scalars have been updated to use two years of historical data.

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

A. Yes. This change increases NPC by approximately $270,000 due to the increasing amount of reserves required to be held on the system as a result of increasing intermittent resources in the Company's generation portfolio.

Q. Please describe the OFPC scalars and the updates PacifiCorp has made to the scalars in the 2021 TAM.

A. The Company-proposed scalar methodology was agreed to in the 2020 TAM stipulation, which used the CAISO day-ahead hourly market prices at the COB and PV market hubs to scale the OFPC. The updated scalars produce a more reasonable hourly shape with a peak in the morning hours, valley shape during mid-day, and a larger peak in the evening hours. However, in the 2020 TAM, the Company used 12 months of market prices when developing the scalars due to a step change in solar penetration in the market. In the 2021 TAM, in response to concerns from parties, the Company updated the scalar methodology to use 24 months of historical CAISO data. This will reduce the influence of abnormal events while ensuring that data is drawn from the historical periods that are most representative of conditions in the forecast period. Updating to the 24-month scalars reduced NPC by $435,000. This change in data inputs to determine the hourly scalars does not alter the application of the scalars to the OFPC.

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[8] *Pacific Power & Light Company 2019 Integrated Resource Plan*, Docket No. LC-70, Volume II at Appendix F.

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 2021 TAM. This notice was provided on January 15, 2020, and is included as Exhibit PAC/105.

VIII. 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.[9] As part of a provision in the stipulation for the 2020 TAM, PacifiCorp agreed to not apply inflation to the fixed generation costs in years six through 10.[10]

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.

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[9] *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).

[10] *In the Matter of PacifiCorp d/b/a Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351, Appendix A at 10 (Oct. 30, 2019).

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. Is the calculation of the Consumer Opt-Out Charge in the 2021 TAM consistent with the stipulation filed in the 2020 TAM?[11]

A. Yes.

IX. 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

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[11] *Id.*

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.[12]

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

X. COMPLIANCE WITH TAM GUIDELINES

Q. Did the Company prepare this filing in accordance with the TAM Guidelines adopted by Order 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 TAM concurrently filed with a general rate case.

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

A. Yes.

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[12] *PacifiCorp Schedule 193 New Large Load Direct Access Program*, Docket No. ADV-900, Advice No. 18-010, acknowledged Feb. 26, 2019

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

A. Yes. Exhibit PAC/106 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?

A. Yes. The Company has provided the step-log as Exhibit PAC/104.

Q. Did the Company provide pre-filing notice to the parties of modeling and input changes in the 2021 TAM?

A. Yes. PacifiCorp's notice of substantial changes to the Company's modeling of NPC in the 2021 TAM, provided on January 15, 2020, is included as Exhibit PAC/105.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 356
Exhibit PAC/101
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

Oregon-Allocated Net Power Costs

February 2020

PacifiCorp
CY 2021 TAM
Initial Filing

			Total Company					**Oregon Allocated**	
Line no		ACCT.	UE-356 CY 2020 - Final Update	TAM CY 2021 - Initial Filing	Factor	Factors CY 2020	Factors CY 2021	UE-356 CY 2020 - Final Update	TAM CY 2021 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	7,454,128	7,542,788	SG	26.456%	26.023%	1,972,052	1,962,832
3	Existing Firm UPL	447	-	-	SG	26.456%	26.023%	-	-
4	Post-Merger Firm	447	422,493,915	274,078,000	SG	26.456%	26.023%	111,774,336	71,322,311
5	Non-Firm	447	-	-	SE	25.314%	25.101%	-	-
6	**Total Sales for Resale**		429,948,043	281,620,789				113,746,388	73,285,143
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	11,573,498	2,848,086	SG	26.456%	26.023%	3,061,867	741,147
10	Existing Firm Demand UPL	555	3,793,812	2,484,823	SG	26.456%	26.023%	1,003,685	646,616
11	Existing Firm Energy	555	37,613,980	15,046,383	SE	25.314%	25.101%	9,521,753	3,776,866
12	Post-merger Firm	555	674,728,706	592,134,446	SG	26.456%	26.023%	178,505,181	154,088,971
13	Secondary Purchases	555	-	-	SE	25.314%	25.101%	-	-
14	Other Generation Expense	555	7,454,837	-	SG	26.456%	26.023%	1,972,240	-
15	**Total Purchased Power**		735,164,833	612,513,738				194,064,726	159,253,600
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	22,079,714	21,615,814	SG	26.456%	26.023%	5,841,375	5,625,004
19	Existing Firm UPL	565	-	-	SG	26.456%	26.023%	-	-
20	Post-merger Firm	565	106,215,175	114,763,115	SG	26.456%	26.023%	28,100,122	29,864,384
21	Non-Firm	565	3,175,158	2,694,259	SE	25.314%	25.101%	803,772	676,299
22	**Total Wheeling Expense**		131,470,047	139,073,187				34,745,269	36,165,687
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	655,082,891	612,737,366	SE	25.314%	25.101%	165,830,293	153,806,196
26	Fuel Consumed - Coal (Cholla)	501	36,986,850	-	SE	25.314%	25.101%	9,362,999	-
27	Fuel Consumed - Gas	501	7,690,635	6,894,972	SE	25.314%	25.101%	1,946,838	1,730,741
28	Natural Gas Consumed	547	297,308,679	303,050,501	SE	25.314%	25.101%	75,261,903	76,070,185
29	Simple Cycle Comb. Turbines	547	4,355,357	3,721,741	SE	25.314%	25.101%	1,102,532	934,212
30	Steam from Other Sources	503	4,676,489	4,519,705	SE	25.314%	25.101%	1,183,825	1,134,513
31	**Total Fuel Expense**		1,006,100,902	930,924,285				254,688,390	233,675,847
32									
33	TAM Settlement Adjustment**		(1,467,719)	-		As Settled		(388,297)	-
34									
35	**Net Power Cost (Per GRID)**		1,441,320,020	1,400,890,421				369,363,700	355,809,991
36									
37	Oregon Situs NPC Adustments		522,082	786,770	OR	100.000%	100.000%	522,082	786,770
38	**Total NPC Net of Adjustments**		1,441,842,102	1,401,677,191				369,885,782	356,596,762
39									
40	Non-NPC EIM Costs*		1,456,461	-	SG	26.456%	26.023%	385,319	-
41	Production Tax Credit (PTC)		(96,935,002)	(248,328,203)	SG	26.456%	26.023%	(25,644,974)	(64,621,536)
42	**Total TAM Net of Adjustments**		1,346,363,561	1,153,348,988				344,626,127	291,975,226
43									
44								Increase Absent Load Change	(52,650,901)
45									
46			Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-356					$344,626,127	
47			$ Change due to load variance from UE-356 forecast					(3,440,369)	
48			2021 Recovery of NPC (incl. PTC) in Rates					$341,185,758	
49	*EIM Benefits for the 2020 TAM are reflected in net power costs								
50	**TAM Settlement UE 356 - Agreed to decrease Oregon-allocated NPC by $388,297.							**Increase Including Load Change**	**$ (49,210,532)**

Docket No. UE 375
Exhibit PAC/102
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

Net Power Costs Report

February 2020

Exhibit PAC/102
Webb/1

PacifiCorp

ORTAM21 NPC CONF CONF

Net Power Cost Analysis

12 months ended December 2021	01/21-12/21	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,542,788	737,263	570,304	528,395	352,233	381,252	630,132	745,513	736,443	731,878	698,753	679,593	751,029
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	10,163	847	847	847	847	847	847	847	847	847	847	847	847
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	110,091	6,811	7,295	10,304	5,026	5,690	5,945	16,774	16,065	12,717	8,713	6,709	8,041
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,663,042	744,921	578,446	539,546	358,106	387,789	636,924	763,134	753,354	745,442	708,312	687,149	759,917
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	4,870,100	1,646,150	1,524,600	1,699,350	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	4,870,100	1,646,150	1,524,600	1,699,350	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	52,476,752	5,044,481	3,794,566	3,224,874	1,759,668	3,872,753	3,213,653	5,078,927	5,304,453	6,342,943	4,656,226	5,192,368	4,991,841
Four Corners	77,051,414	8,347,442	4,724,313	4,183,682	2,973,776	2,672,188	4,936,360	7,320,298	9,352,086	12,194,004	6,565,828	5,569,210	8,212,227
Mead	34,748,637	3,614,103	3,738,208	3,269,381	1,839,651	1,930,895	2,189,676	1,839,774	4,292,734	2,862,948	3,165,662	2,787,574	3,218,030
Mid Columbia	26,494,386	2,512,143	627,697	439,735	1,735,364	2,162,706	1,233,071	5,496,676	4,872,707	2,741,234	2,380,756	1,366,526	925,772
Mona	32,551,737	3,858,977	2,274,389	1,106,693	816,810	1,630,297	2,828,137	3,434,790	3,356,443	5,845,723	2,483,596	2,020,039	2,895,844
NOB	3,726,697	-	38,067	173,301	602,194	-	-	1,034,147	1,129,866	672,276	-	-	76,847
Palo Verde	41,944,638	2,071,482	628,789	1,214,405	2,193,118	3,048,990	4,341,144	6,619,932	7,891,093	4,754,917	2,904,372	2,813,221	3,463,174
Trapped Energy	93,385	87,538	161	-	-	-	-	-	-	-	2,754	1,238	1,694
Total System Balancing Sales	269,087,647	25,536,166	15,826,189	13,612,071	11,920,581	15,317,830	18,742,042	30,824,544	36,199,382	35,414,045	22,159,194	19,750,175	23,785,429
Total Special Sales For Resale	281,620,789	27,927,237	17,929,235	15,850,968	12,278,687	15,705,618	19,378,966	31,587,678	36,952,736	36,159,487	22,867,506	20,437,324	24,545,346

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,369,183	372,730	451,629	548,064	547,356	467,185	400,360	449,667	380,464	356,392	373,503	454,868	566,965
Cove Mountain Solar	3,863,906	185,318	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,150
Cove Mountain Solar II	1,378,653	-	-	-	-	-	-	477,599	446,146	312,233	129,370	13,304	-
Deseret Purchase	32,857,509	2,915,824	2,814,518	2,621,790	2,352,460	2,337,634	2,725,566	2,928,178	2,928,178	2,898,528	2,679,855	2,726,802	2,928,178
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,615,653	156,892	141,048	125,873	128,817	154,170	284,603	436,745	407,435	241,073	156,349	153,679	228,968
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter Solar	7,122,324	374,917	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,602
Hurricane Purchase	157,969	13,164	13,164	13,164	13,164	13,164	13,164	13,164	13,164	13,164	13,164	13,164	13,164
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	5,084,680	421,050	425,060	421,050	421,050	421,050	421,050	409,020	429,070	429,070	429,070	429,070	429,070
Milican Solar	2,646,179	68,661	138,221	204,961	257,983	306,199	333,290	375,334	331,656	266,914	174,771	111,940	76,250
Milford Solar	7,081,219	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	394,020	310,716
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	1,795,505	82,013	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,717
Rock River Wind	3,946,224	646,275	501,909	527,308	435,866	283,847	261,471	181,190	192,923	261,614	490,103	163,718	-
Sigurd Solar	5,977,024	312,681	349,111	514,891	562,169	646,129	710,144	660,236	605,234	565,052	458,516	322,228	270,634
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	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,590,359	2,780,878	1,800,587	2,128,069	1,610,055	1,424,706	1,195,953	805,718	951,654	1,177,524	1,732,701	2,340,466	2,642,051
Top of the World Wind	40,561,724	5,419,898	3,601,698	4,231,279	3,257,937	2,901,583	2,391,955	1,714,486	1,871,428	2,285,558	3,506,241	4,474,032	4,905,631
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,280,610	762,136	890,500	1,133,240	1,044,443	790,356	845,645	670,084	640,998	754,456	830,707	962,468	955,576
Long Term Firm Purchases Total	200,976,787	19,663,255	16,597,347	18,436,464	16,731,740	15,822,129	15,626,620	15,045,734	14,720,431	15,309,398	16,826,227	17,542,755	18,654,688
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	2,466,928	216,310	237,207	267,853	313,290	303,374	244,837	166,837	139,017	130,925	134,349	138,692	174,236
QF Idaho	8,526,013	665,205	622,486	675,919	549,840	791,695	853,072	804,323	706,952	676,893	710,906	692,968	775,754
QF Oregon	51,801,171	3,002,824	3,169,852	4,140,008	5,143,180	5,590,917	5,823,344	5,679,229	5,370,766	4,654,714	3,670,563	2,717,089	2,838,685
QF Utah	11,686,984	799,972	834,747	994,336	1,035,869	1,137,833	1,155,642	1,078,323	1,069,390	1,006,203	958,094	845,641	770,935
QF Washington	208,630	-	-	-	3,598	16,682	34,292	47,832	51,603	41,039	13,584	-	-
QF Wyoming	148,999	14,566	13,067	14,455	11,422	10,419	8,672	12,538	12,397	9,613	12,059	12,525	17,264
Biomass One QF	14,791,130	1,137,736	1,042,736	1,192,638	1,605,813	1,011,587	995,146	1,437,452	1,393,486	1,388,503	1,437,697	1,426,922	721,416
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	151,169	3,390	6,084	5,901	4,769	4,661	7,241	24,396	30,029	28,961	17,679	11,260	6,796
Enterprise Solar I QF	12,565,251	618,303	756,852	985,653	1,115,324	1,255,980	1,384,633	1,549,498	1,503,902	1,182,205	958,096	707,925	546,881
Escalante Solar I QF	11,633,431	567,021	680,951	928,583	1,019,621	1,191,002	1,306,995	1,424,978	1,390,261	1,093,877	875,343	645,179	509,621
Escalante Solar II QF	10,913,161	532,831	639,708	835,963	959,353	1,125,876	1,236,165	1,346,489	1,305,289	1,031,715	820,808	603,620	475,344
Escalante Solar III QF	10,508,750	518,662	625,371	809,560	927,465	1,098,872	1,207,167	1,309,506	1,268,668	1,003,541	751,202	552,982	435,755
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,449,185	516,272	844,647	761,925	794,324	483,155	552,309	637,981	597,909	755,820	737,311	884,763	882,768
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,904,092	549,588	617,041	897,068	990,647	1,158,077	1,259,308	1,331,161	1,260,573	977,914	811,198	583,169	468,346
Granite Mountain West Solar QF	7,225,470	363,870	408,682	599,461	658,359	766,651	833,319	881,233	834,746	646,982	536,860	385,681	309,627
Iron Springs Solar QF	11,192,631	635,330	664,037	898,798	1,017,392	1,129,261	1,284,984	1,341,703	1,318,741	1,005,130	816,809	579,976	500,469
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,740	1,007,477	917,570	1,126,955	897,120	856,897	745,979	673,722	567,152	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,964,749	1,398,213	1,052,662	881,515	690,757	484,084	504,631	418,353	446,738	468,249	671,093	924,344	1,024,110
Mountain Wind 2 QF	13,957,983	2,035,458	1,574,052	1,356,165	1,074,123	756,310	911,425	782,136	745,596	774,604	1,006,261	1,427,689	1,514,164
North Point Wind QF	18,851,249	1,081,842	1,816,464	1,693,531	1,781,293	1,076,566	1,246,466	1,476,915	1,478,098	1,791,786	1,710,791	1,875,172	1,822,326
Oregon Wind Farm QF	12,459,615	720,850	962,190	1,110,088	1,326,635	1,241,453	1,222,923	1,252,276	1,122,867	919,265	727,686	816,390	1,036,992
Pavant II Solar QF	4,301,202	177,692	223,855	347,731	397,651	454,269	475,364	554,324	544,488	422,853	330,367	205,704	166,905
Pioneer Wind Park I QF	10,652,046	1,307,478	925,801	1,189,078	900,980	708,747	652,357	655,291	688,227	448,742	821,303	1,257,878	1,096,164
Power County North Wind QF	5,536,084	419,102	555,296	534,072	523,126	356,418	363,992	371,577	371,875	382,893	515,554	535,686	606,494
Power County South Wind QF	4,944,022	370,734	489,784	483,169	486,679	308,194	325,756	329,224	347,357	339,588	452,143	484,867	526,526
Roseburg Dillard QF	1,046,604	52,652	45,323	49,453	117,831	106,620	104,258	159,962	110,362	65,642	83,730	92,295	58,477
Sage I Solar QF	2,270,456	80,679	79,891	190,158	206,003	234,995	262,709	337,883	333,611	208,547	155,711	104,870	75,399
Sage II Solar QF	2,272,891	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,976	208,784	155,870	105,000	75,469
Sage III Solar QF	1,870,483	68,007	66,563	157,054	167,907	192,623	214,874	275,730	272,050	172,117	130,624	88,886	64,050
Spanish Fork Wind 2 QF	2,716,508	215,278	175,207	201,250	159,298	150,380	209,852	286,290	305,876	268,904	239,128	247,888	257,158
Sunnyside QF	31,141,210	2,757,966	2,577,196	2,680,631	1,719,211	2,720,081	2,750,586	2,771,141	2,789,878	2,600,557	2,388,430	2,744,822	2,640,710
Sweetwater Solar QF	7,797,376	259,240	374,746	567,022	689,492	814,366	985,566	1,121,979	1,038,739	815,928	628,052	300,112	202,134
Tesoro QF	327,318	50,859	22,516	27,152	24,386	45,902	8,670	12,843	19,814	18,835	22,119	27,137	47,086
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,443,830	412,955	475,771	627,986	834,968	858,311	911,398	1,037,026	998,447	794,117	672,625	445,987	374,238
Utah Pavant Solar QF	5,598,461	209,811	240,058	409,487	469,821	565,103	660,594	768,175	717,181	597,472	450,464	279,094	231,200
Utah Red Hills Solar QF	11,555,073	483,928	618,944	789,247	1,033,577	1,201,833	1,244,082	1,526,296	1,465,137	1,326,474	810,010	590,102	465,442
Qualifying Facilities Total	337,554,895	23,332,866	24,437,343	28,620,223	29,857,348	30,444,402	32,251,613	34,222,864	32,951,198	28,876,078	26,033,773	24,052,006	22,475,182
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,136,095	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	2,136,095	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008
Total Long Term Firm Purchases	540,667,778	43,174,128	41,212,698	47,234,695	46,767,096	46,444,538	48,056,242	49,446,606	47,849,636	44,363,484	43,038,007	41,772,769	41,307,878

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	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	15,870,037	780,013	1,979,144	1,008,225	498,260	519,393	1,528,670	2,664,595	2,341,617	1,317,011	67,700	591,653	2,573,756
Four Corners	18,416,331	1,154,869	2,278,797	3,300,299	2,520,614	672,614	412,469	281,811	231,303	2,013,615	1,809,097	1,985,535	1,755,307
Mead	6,079,955	205,403	498,865	759,795	524,017	479,904	537,594	604,796	554,129	822,516	375,698	270,725	446,512
Mid Columbia	70,206,727	8,074,175	2,034,817	407,330	3,923,111	12,649,311	7,884,843	15,774,229	11,741,793	3,773,166	846,473	1,366,129	1,731,349
Mona	10,444,093	1,383,513	1,170,405	714,033	617,855	760,655	73,643	935,101	911,436	395,989	1,232,763	1,054,013	1,194,688
NOB	7,965,312	-	126,177	364,901	878,936	-	2,759	2,559,132	2,277,129	1,599,282	-	-	156,995
Palo Verde	1,264,434	105,369	105,369	105,369	105,369	105,369	105,369	105,369	105,369	105,369	105,369	105,369	105,369
EIM Imports/Exports	(64,594,041)	(3,477,483)	(3,102,409)	(8,578,822)	(8,746,296)	(8,972,657)	(3,177,393)	(6,964,351)	(7,193,600)	(4,914,121)	(2,979,604)	(2,911,632)	(3,575,674)
Emergency Purchases	793,114	416,270	47,688	97,968	85,612	13,290	8,344	54,604	9,147	113	24,860	6,371	28,846
Total System Balancing Purchases	66,445,960	8,642,129	5,138,853	(1,820,901)	407,478	6,227,881	7,376,298	16,015,287	10,978,323	5,112,940	1,482,357	2,468,164	4,417,150
Total Purchased Power & Net Interc	612,513,737	52,266,257	46,801,551	45,863,794	47,624,574	53,122,419	55,882,540	65,911,893	59,277,959	49,926,424	44,970,365	44,690,933	46,175,028

Wheeling & U. of F. Expense													
Firm Wheeling	136,816,856	11,964,608	11,486,264	11,322,124	10,788,677	10,628,291	11,316,211	11,934,751	11,525,886	11,247,413	11,010,612	11,373,647	12,218,372
C&T EIM Admin fee	2,180,059	153,010	131,133	172,440	211,710	248,077	216,704	195,675	190,485	165,386	162,857	159,298	173,283
ST Firm & Non-Firm	76,272	12,396	7,721	1,157	-	694	1,613	6,274	5,487	28,217	3,656	3,473	5,585
Total Wheeling & U. of F. Expense	139,073,187	12,130,014	11,625,118	11,495,722	11,000,387	10,877,062	11,534,528	12,136,700	11,721,858	11,441,016	11,177,125	11,536,418	12,397,241
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	16,438,683	1,760,980	1,427,071	1,397,028	1,115,497	955,803	1,140,537	1,677,245	1,715,988	1,498,561	918,143	1,138,440	1,693,390
Craig	17,499,897	1,493,432	1,373,106	1,331,178	1,374,535	1,244,443	1,166,366	1,566,648	1,641,509	1,560,768	1,767,340	1,373,704	1,606,867
Dave Johnston	48,459,229	3,906,376	3,756,390	3,688,235	3,295,931	3,181,821	3,651,088	4,799,257	5,279,991	4,453,890	4,375,241	3,764,558	4,306,450
Hayden	14,769,365	1,280,299	1,145,419	1,258,445	960,773	1,354,403	1,342,650	1,339,682	1,245,636	1,345,872	830,414	1,326,981	1,338,791
Hunter	108,641,852	13,811,021	8,335,066	5,580,973	1,731,110	2,427,750	6,985,461	12,002,470	11,910,065	10,378,968	8,946,648	12,125,508	14,406,813
Huntington	94,054,145	10,357,767	8,501,224	7,890,374	5,534,289	5,043,902	5,165,631	9,307,453	9,414,447	6,984,619	5,478,836	8,228,675	12,146,928
Jim Bridger	205,967,584	15,459,576	15,661,390	17,801,557	12,450,728	11,744,227	15,915,015	24,177,526	23,490,147	17,374,744	17,475,746	17,750,175	16,666,751
Naughton	78,436,167	7,664,308	6,721,679	6,707,145	4,590,654	4,102,588	5,480,598	7,455,979	7,564,135	7,395,158	6,308,646	7,177,469	7,267,808
Wyodak	28,470,445	2,467,655	2,559,135	1,771,019	1,850,068	2,542,075	2,349,502	2,853,374	2,699,868	2,539,399	2,564,657	2,374,588	1,899,105
Total Coal Fuel Burn Expense	612,737,366	58,201,415	49,480,481	47,425,954	32,903,585	32,597,013	43,196,846	65,179,635	64,961,786	53,531,980	48,665,670	55,260,098	61,332,903
Gas Fuel Burn Expense													
Chehalis	46,981,173	3,206,232	1,042,209	3,174,642	3,408,181	3,816,631	3,057,599	4,967,854	5,115,524	4,908,768	5,290,126	3,597,550	5,395,857
Currant Creek	49,855,648	3,924,409	3,791,765	3,192,176	2,956,191	3,791,247	4,206,673	4,994,533	4,938,755	4,866,245	4,519,259	4,005,144	4,669,250
Gadsby	5,407,793	373,820	449,646	259,135	237,216	286,428	287,464	854,114	787,581	548,110	274,321	314,588	735,371
Gadsby CT	2,842,175	290,866	265,636	142,852	148,707	98,145	111,533	451,469	364,997	287,517	111,651	146,875	421,927
Hermiston	20,830,602	1,492,897	1,045,231	1,182,728	1,865,268	651,707	1,330,287	2,061,179	2,254,257	2,194,284	2,356,058	2,426,611	1,970,096
Lake Side 1	57,595,194	4,621,783	4,679,478	4,365,345	4,196,251	4,505,408	4,704,958	5,726,837	5,787,438	5,475,551	4,603,773	4,353,620	4,574,753
Lake Side 2	54,216,395	5,605,832	4,665,951	4,384,665	4,342,655	4,058,083	4,901,269	4,216,879	4,318,169	4,181,427	3,941,936	4,159,289	5,440,240
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	23,659,746	1,893,574	1,704,105	1,527,647	2,344,248	2,621,072	2,793,493	1,936,919	1,808,258	1,374,793	1,508,115	1,449,124	2,698,398
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	261,388,727	21,409,413	17,644,021	18,229,190	19,498,717	19,828,721	21,393,275	25,209,784	25,374,979	23,836,694	22,605,240	20,452,801	25,905,891
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	16,864,383	107,958	574,350	2,058,478	1,780,200	1,935,640	1,733,700	1,348,578	1,323,855	1,392,075	2,253,545	1,497,150	858,855
Clay Basin Gas Storage	(29,961)	(132,136)	(104,285)	(29,237)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(25,669)	(104,331)
Pipeline Reservation Fees	35,444,066	2,972,129	2,854,651	2,967,042	2,930,053	2,969,471	2,930,490	2,999,253	2,993,742	2,943,396	2,968,876	2,929,450	2,985,512
Total Gas Fuel Burn Expense	313,667,214	24,357,364	20,968,737	23,225,472	24,261,212	24,786,075	26,109,708	29,609,857	29,744,819	28,224,407	27,879,904	24,853,732	29,645,927
Other Generation													
Blundell	4,519,705	427,340	332,387	425,463	404,195	405,650	375,670	387,532	391,242	392,657	336,656	334,644	306,268
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-												
Dunlap I Wind	-												
Ekola Flats 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	-												
Pryor Mountain Wind	-												

Rolling Hills Wind	-												
Seven Mile Wind	-												
Seven Mile II Wind	-												
Black Cap Solar													
TB Flats Wind													
TB Flats Wind II													
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	4,519,705	427,340	332,387	425,463	404,195	405,650	375,670	387,532	391,242	392,657	336,656	334,644	306,268
Net Power Cost	**1,400,890,421**	119,455,153	111,279,039	112,585,438	103,915,266	106,082,600	117,720,325	141,637,939	129,144,928	107,356,997	110,162,213	116,238,501	125,312,021

REDACTED
Docket No. UE 375
Exhibit PAC/103
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of David G. Webb

Update to Renewable Energy Production Tax Credits

February 2020

REDACTED

PacifiCorp
CY 2021 TAM
Production Tax Credits - Stand Alone TAM Adjustment
Initial Filing

Line no	Plant Name	PTC Expiration Date	Total Company UE-356 Final	Factor	Factors CY 2020	Oregon Allocated UE-356 Final	Oregon Allocated Revenue Requirement
	PTC Revenue Requirement in UE-356						
1	JC Boyle	11/7/2015	$ -	SG	26.456%	$ -	$ -
2	Blundell Bottoming Cycle	12/1/2017	-	SG	26.456%	-	-
3	Glenrock	12/30/2018	(8,519,221)	SG	26.456%	(2,253,832)	(2,988,636)
4	Goodnoe	12/17/2017	(7,140,296)	SG	26.456%	(1,889,026)	(2,504,894)
5	High Plains Wind	10/14/2019	(9,618,301)	SG	26.456%	(2,544,603)	(3,374,205)
6	Leaning Juniper 1	9/13/2016	(7,528,559)	SG	26.456%	(1,991,744)	(2,641,101)
7	Leaning Juniper Indemnity	9/13/2016	(97,871)	SG	26.456%	(25,893)	(34,334)
8	Marengo	8/2/2017	(12,267,120)	SG	26.456%	(3,245,370)	(4,303,440)
9	Marengo II	6/25/2018	(5,843,584)	SG	26.456%	(1,545,969)	(2,049,993)
10	McFadden Ridge	10/31/2019	(2,933,447)	SG	26.456%	(776,068)	(1,029,085)
11	Rolling Hills	1/16/2019	-	SG	26.456%	-	-
12	Seven Mile	12/30/2018	(10,490,109)	SG	26.456%	(2,775,247)	(3,680,045)
13	Seven Mile II	12/30/2018	(2,198,558)	SG	26.456%	(581,647)	(771,278)
14	Dunlap I Wind	9/29/2020	(6,464,915)	SG	26.456%	(1,710,348)	(2,267,963)
15							
16	Total Production Tax Credit		$ (73,101,981)			$ (19,339,747)	$ (25,644,974)
17							
18							
19	**PTC Revenue Requirement CY 2021 - Initital Filing**						
20			**Total Company**			**Oregon Allocated**	
21	Plant Name	PTC Effective Date	CY 2021 Initial Filing	Factor	Factors CY 2021	CY 2021 Initial Filing	Revenue Requirement
22	JC Boyle		[redacted]	SG	26.023%	[redacted]	[redacted]
23	Blundell Bottoming Cycle		[redacted]	SG	26.023%	[redacted]	[redacted]
24	Glenrock	10/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
25	Glenrock III	1/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
26	Goodnoe	10/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
27	High Plains Wind	11/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
28	Leaning Juniper 1	10/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
29	Leaning Juniper Indemnity	10/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
30	Marengo	11/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
31	Marengo II	11/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
32	McFadden Ridge	11/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
33	Rolling Hills	10/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
34	Seven Mile	7/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
35	Seven Mile II	7/1/2019	[redacted]	SG	26.023%	[redacted]	[redacted]
36	Dunlap I Wind	10/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
37	Foote Creek I Wind	11/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
38	Pryor Mountain Wind	12/31/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
39	Cedar Springs Wind II	12/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
40	Ekola Flats Wind	12/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
41	TB Flats Wind	12/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
42	TB Flats Wind II	12/1/2020	[redacted]	SG	26.023%	[redacted]	[redacted]
43							
44	Total Production Tax Credit		$ (187,272,741)			$ (48,733,297)	$ (64,621,536)
45							
46							
47						Oregon-allocated PTC Baseline in Rates from UE-356	$ (25,644,974)
48						2021 Recovery of PTC in Rates	(64,621,536)
49							
50						**Oregon-allocated PTC Increase**	**$ (38,976,562)**

Docket No. UE 375
Exhibit PAC/104
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

Step Log Change

February 2020

2021 TAM Step Log

<table>
<tr><td>ORTAM20</td><td></td><td></td><td>$ 1,441,320,020</td></tr>
<tr><td></td><td>Description</td><td>Detail</td><td>Impact</td></tr>
<tr><td></td><td>Routine Updates</td><td></td><td>(70,566,689)</td></tr>
<tr><td>Step 1</td><td>Scalar for Price Curve</td><td>Apply 24-month rolling CAISO day-ahead hourly prices</td><td>(1,700,033)</td></tr>
<tr><td>Step 2</td><td>2019 Flexble Reserve Study in 2019 IRP</td><td></td><td>1,056,009</td></tr>
<tr><td>Step 3</td><td>Thermal Attributes updates</td><td>
<table>
<tr><th colspan="3">Minimum Operational Level (MW)</th></tr>
<tr><th>Units</th><th>2021 TAM</th><th>2020 TAM</th></tr>
<tr><td>Dave Johnson 4</td><td>150</td><td>180</td></tr>
<tr><td>Hermiston 1</td><td>77</td><td>154</td></tr>
<tr><td>Hermiston2</td><td>77</td><td>154</td></tr>
<tr><td>Hunter 1</td><td>70.3</td><td>79.68</td></tr>
<tr><td>Hunter 2</td><td>51.3</td><td>78.4</td></tr>
<tr><td>Hunter 3</td><td>60</td><td>72</td></tr>
<tr><td>Huntington 1</td><td>70</td><td>80</td></tr>
<tr><td>Jim Bridger 1</td><td>33.3</td><td>80</td></tr>
<tr><td>Jim Bridger 2</td><td>26.7</td><td>53.3</td></tr>
<tr><td>Jim Bridger 3</td><td>43.3</td><td>80</td></tr>
<tr><td>Jim Bridger 4</td><td>133.3</td><td>80</td></tr>
</table>
</td><td>4,074,177</td></tr>
<tr><td>Step 4</td><td>Coal Plant Economic Cycling</td><td></td><td>(164,934)</td></tr>
<tr><td>Step 5</td><td>Cholla 4 Closure</td><td>Cholla 4 Closure and Transmission rights expiration</td><td>29,311,753</td></tr>
<tr><td>Step 6</td><td>Naughton 3 gas conversion</td><td></td><td>(2,439,883)</td></tr>
<tr><td>ORTAM21</td><td></td><td></td><td>$ 1,400,890,421</td></tr>
</table>

Docket No. UE 375
Exhibit PAC/105
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

January 15, 2020 Notice Letter

February 2020

Exhibit PAC/105
Webb/1

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

January 15, 2020

VIA ELECTRONIC MAIL

Attn: Parties to docket UE 356

RE: 2021 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 2021 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] Because PacifiCorp plans to file a general rate case on February 14, 2020, concurrently with the 2021 TAM, the company is providing this notice to comply with the pre-filing review requirement and the methodology change notice requirement.

PacifiCorp provides notice of the following planned changes to the 2021 TAM:
- The regulating reserve requirements will be updated to be consistent with the flexible reserve study in the PacifiCorp 2019 Integrated Resource Plan.
- The scalars applied to the official forward price curve are updated by using a two-year history from the California Independent System Operator data.
- A workshop has been scheduled to work collaboratively with parties to discuss a methodology for forecasting Energy Imbalance Market benefits. PacifiCorp will include an exhibit to testimony in the direct filing identifying all changes as outlined above.

Please direct any questions regarding this notice to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Michael Wilding
Director, Net Power Costs and Regulatory Policy

cc: UE 356 Service List

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[1] Generation and Regulation Initiative Decision Tools model.

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

Docket No. UE 375
Exhibit PAC/106
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

List of Expected or Known Contract Updates

February 2020

Exhibit PAC/106
Webb/1

List of Known Items Expected to be Updated During the 2021 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.
7. Purchase contracts for generation and fixed costs from the Mid-Columbia projects.
8. Purchase expenses of PGE Cove based on PGE projection.
9. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

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

Wheeling Expenses and Transmission

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

Other

17. Energy Imbalance Market benefit estimates, including import and export margins and volumes, as well as greenhouse gas benefits.

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							√	√
Colstrip	Westmoreland/Rosebud					√	√	n/a	n/a
Craig	Trapper Mining Inc/Trapper	√	n/a						
Hayden	Peabody/Twentymile			√	n/a				
	Union Pacific Railroad							√	√
Hunter	Unidentified Utah			√	√				
	Utah Trucking							√	√
Huntington	Wolverine/Sufco, Dugout, Skyline			√	√				
	Utah Trucking							√	√
D Johnston	Unidentified PRB					√	√		
	Peabody/Caballo			n/a	n/a				
	Coal Creek/Arch			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 375
Exhibit PAC/200
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Ramon J. Mitchell

February 2020

TABLE OF CONTENTS

ATTACHED EXHIBITS

Confidential Exhibit PAC/201—EIM Inter-Regional Transfer Benefits – Statistical Model Overview

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Ramon J. Mitchell. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Organized Market Analyst.

Q. Briefly describe your education and professional experience.

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I have worked for PacifiCorp since August 2015, during which time I have worked on production cost models in the context of net power costs (NPC) and on market policy and analytics in the context of the Western Energy Imbalance Market (EIM).

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony sponsors PacifiCorp's forecast of its EIM inter-regional transfer benefits and EIM greenhouse gas (GHG) benefits for calendar year 2021, which has been updated using the most recent EIM benefit information through December 2019.

Q. Please summarize your testimony.

A. PacifiCorp's participation in the EIM reduces NPC through more efficient economic dispatch, inter-regional transfers, reduced regulation reserve requirements and GHG revenue opportunities.

My testimony supports PacifiCorp's 2021 EIM inter-regional transfer benefit forecast of [redacted]. The Company's forecast of EIM inter-regional transfer benefits is modeled based on the inputs used in the calculation of actual EIM inter-regional transfer benefits and maintains consistency with the bilateral market prices that drive the forecast NPC using the Company's Generation and Regulation Initiative Decision Tools (GRID) model. By utilizing the same inputs, the forecast of EIM inter-regional transfer benefits, the calculation of actual EIM inter-regional transfer benefits, and the forecast NPC are aligned and produce a forecast of EIM inter-regional transfer benefits that is just and reasonable.

In addition to PacifiCorp's EIM inter-regional transfer benefit, my testimony also supports the 2021 EIM GHG benefit forecast of [redacted]. The Company's forecast of EIM GHG benefits uses a shaped simple average of historical data in line with the more recent historical information and changes in the policy environment surrounding GHG policy in the EIM.

III. PACIFICORP'S PARTICIPATION IN THE EIM

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 a footprint that includes PacifiCorp, the California Independent System Operator (CAISO), and many other EIM participants.[1] Through the EIM, the Company's participating generation units are optimally scheduled and dispatched using the CAISO's security constrained unit commitment and economic dispatch models.

---

[1] Nevada Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Powerex, Idaho Power Company, Balancing Authority of Northern California (Sacramento Municipal Utility District) currently participate in the EIM.

Q. How do PacifiCorp customers benefit from participation in the EIM?

A. Participation in the EIM benefits customers by reducing PacifiCorp's actual NPC in four ways. First, the EIM facilitates energy transactions between CAISO, PacifiCorp, and other EIM participants on a five- and 15- minute basis (i.e., inter-regional transfer benefits). Second, the EIM allocates energy imported into the CAISO to meet California's GHG compliance obligations, and resources external to the CAISO receive a payment for GHG compliance costs when they are dispatched to serve these obligations (i.e., GHG benefits). Third, the EIM optimizes the scheduling and dispatch of participating units in PacifiCorp's balancing authority area (BAA), subject to transmission constraints, using the CAISO's models (i.e., intra-regional benefits). Fourth, 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 benefits). As stated above, my testimony supports the forecast of EIM inter-regional transfer benefits and GHG benefits in this proceeding.

IV. FORECASTING EIM INTER-REGIONAL TRANSFER BENEFITS

Market Fundamentals Analysis

Q. Please describe PacifiCorp's actual EIM inter-regional transfer benefits.

A. The actual inter-regional transfer benefits are the benefits received by PacifiCorp when it economically exports and imports energy to and from the EIM to displace a more expensive PacifiCorp resource. The benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the Company's calculation of EIM benefits is the marginal cost to produce an additional megawatt-hour (MWh). 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 production cost of the generation that would have otherwise been dispatched. The EIM inter-regional transfer benefits are reflected in actual NPC through lower fuel costs and increased wholesale sales revenue.

Q. How does the Company forecast EIM inter-regional transfer benefits?

A. The Company uses historical actual EIM inter-regional transfer benefits in statistical models to forecast EIM transfer benefits as a function of market prices and transfer volume inputs, which are the underlying drivers of actual EIM transfer benefits. The price inputs are the energy and natural gas market prices from the Official Forward Price Curve (OFPC). The transfer volume inputs are the total transfer capacity of transmission along with spring oversupply conditions, based on the current and expected solar capacity in California. This market fundamentals approach to forecasting EIM transfer benefits mimics the method which the Company uses to calculate actual EIM transfer benefits and maintains consistency with the bilateral market price inputs that drive the Company's forecast NPC. By utilizing the same inputs, the forecast of EIM inter-regional transfer benefits, the calculation of actual EIM inter-regional transfer benefits, and the forecast NPC are aligned and produce a reasonable forecast of EIM inter-regional transfer benefits. The Company's forecast of 2021 EIM inter-regional transfer benefits is [redacted].

Q. Why is it important to have an EIM inter-regional transfer benefit forecast that utilizes the same price inputs as the forecast NPC?

A. The forecast NPC is driven by expectations of market prices. These prices also drive the EIM dispatch of PacifiCorp's generation in real-time operations and the Company's EIM transfer benefits are a direct result of this generation dispatch. If PacifiCorp attempts to forecast EIM transfer benefits without taking into consideration the expectation of market prices the result will be similar to an attempt to forecast NPC without using market prices. Specifically, if forecasts of fuel costs and wholesale market transactions in NPC requires market price inputs then the forecasts of EIM transactions and associated fuel costs must also require the same market price inputs.

Q. Please provide an example of the consequence of failing to have an EIM inter-regional transfer benefit forecast that does not use any price inputs.

A. Consider a hypothetical, two-hour scenario in GRID where the market price is $25/MWh in the first hour and $40/MWh in the second hour with sales of 100 MWh in the bilateral market and incremental sales of 10 MWh in the EIM in each of the two hours. If GRID and the EIM transfer benefit forecast use the same market prices then the second hour would result in increased wholesale sales' revenue of $1,500 from the bilateral market and $150 from the EIM, reducing NPC by $1,650. However, if the EIM transfer benefit forecast does not use the same market prices as an input then forecast NPC for the EIM benefit could either be higher or lower, and it would be inconsistent with the expected drivers of the underlying market fundamentals and overall net power costs.

Q. To further support the importance of using the same market prices in the NPC forecast and the EIM benefit forecast, is there evidence of the benefits of using models driven by market fundamentals to forecast EIM transfer benefits?

A. Yes. There is evidence that EIM transfer benefits are driven by market fundamentals such as market power prices, spring oversupply conditions and total transfer capacity of transmission. Additionally, the premise of this forecasting methodology is that since these fundamentals are forecast then the related EIM transfer benefits can also be forecast. It is important to create a forecast of EIM transfer benefits that is based on the market fundamentals which drive the benefits.

Q. Can you provide examples showing that EIM transfer benefits are driven by market fundamentals?

A. Yes. Illustrated below are relationships between EIM transfer benefits, bilateral market power prices, spring oversupply conditions and total transfer capacity of transmission.

Figure 1

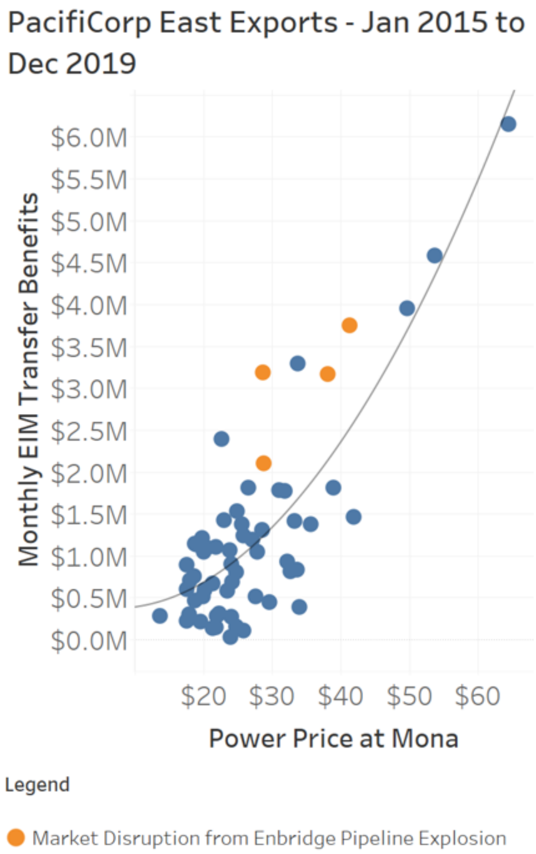


Figure 1 illustrates the relationship between PacifiCorp's EIM transfer benefits of PacifiCorp East Balancing Authority Area (PACE) exports and the day-ahead power prices at the Mona hub. The trend illustrates that as power prices increase, EIM transfer benefits of PACE exports inrease proportionally.

Figure 2

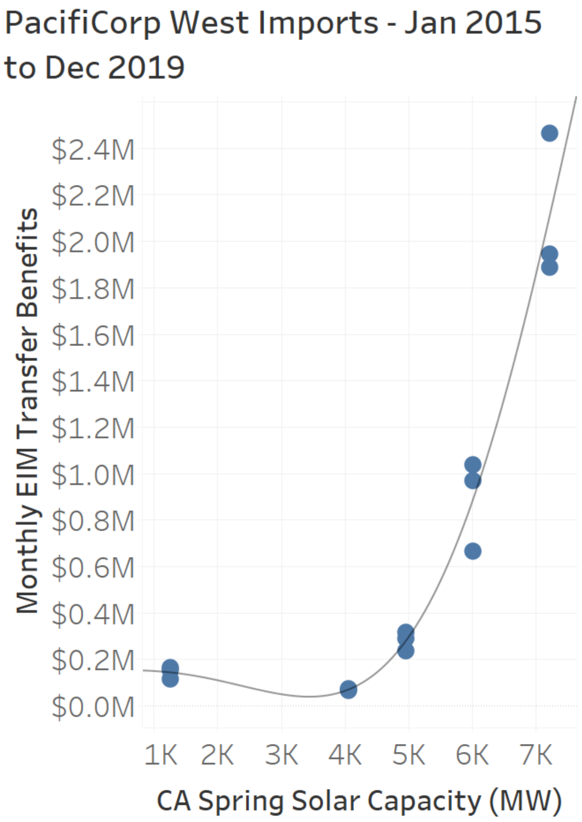


Figure 2 illustrates the relationship between PacifiCorp's EIM transfer benefits of PacifiCorp West Balancing Authority Area (PACW) imports during the spring and the solar capacity installed in California. The trend illustrates that as more solar generators are brought online in California, EIM transfer benefits of imports inrease as well.

Figure 3

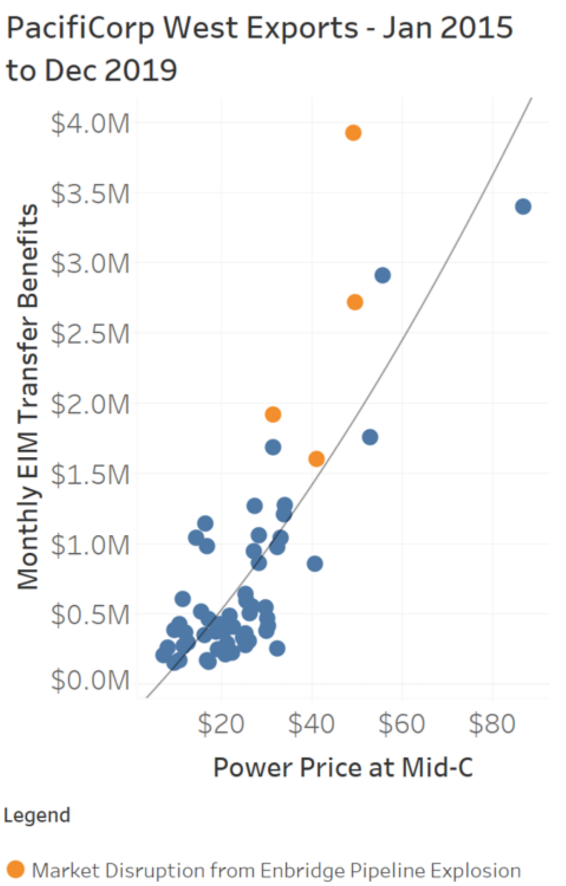
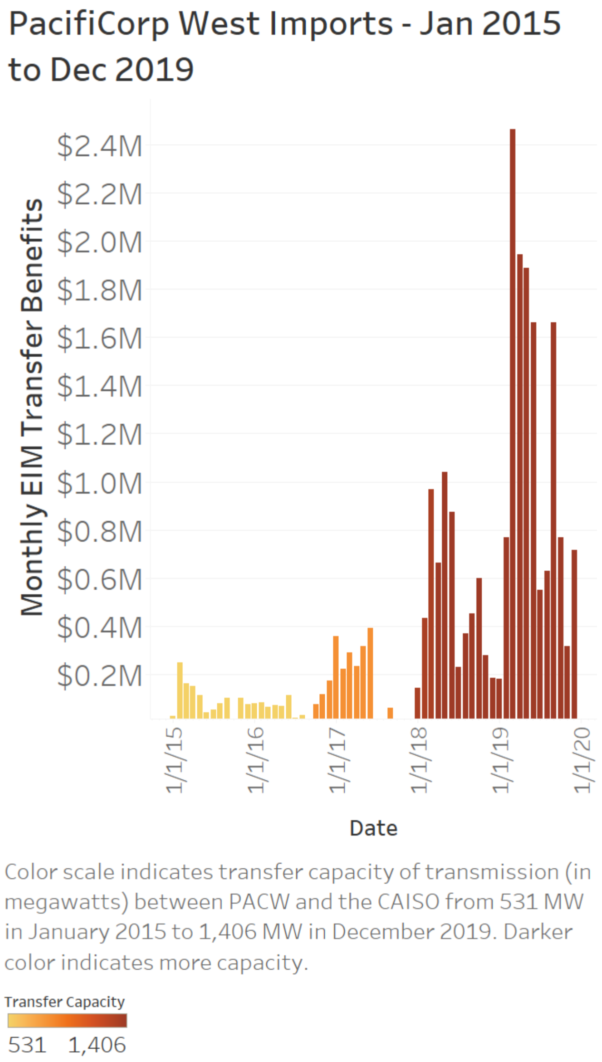


Figure 3 illustrates the relationship between PacifiCorp's EIM transfer benefits of PACW exports and the day-ahead power prices at the Mid-Columbia hub. The trend illustrates that as power prices increase, EIM transfer benefits of PACW exports increase proportionally.

Figure 4



Color scale indicates transfer capacity of transmission (in megawatts) between PACW and the CAISO from 531 MW in January 2015 to 1,406 MW in December 2019. Darker color indicates more capacity.

Figure 4 illustrates the relationship between PacifiCorp's EIM transfer benefits of PACW imports and the total transfer capacity of transmission from the CAISO to PACW. The trend illustrates that as more transmission is brought into the market, the EIM transfer benefits of PACW imports increase correspondingly, such as Idaho Power's entrance into the market in April 2018 and subsequent increase in benefits in PACW. However, the anticipated EIM entrants for 2020 and 2021 are not expected to increase PacifiCorp's transfer capability with the CAISO.

Q. How does the 2021 EIM inter-regional transfer benefit forecast compare to previous years?

A. The 2018 actual EIM transfer benefits were [redacted] and the 2019 actual EIM transfer benefits were [redacted]. With updated data, PacifiCorp's market fundamentals analysis forecasts [redacted] of EIM transfer benefits in 2021. This is illustrated below in Confidential Figure 5.

Confidential Figure 5

[redacted]

Additional detail on the statistical models can be found in the 'Descriptive Statistics' subsection of the 'Appendix' in Exhibit PAC/201.

Q. EIM transfer benefits from 2015 to 2017 exhibit an upward trend. Why does this trend seem to "flatten" in the 2018 and 2019 EIM actual results?

A. PacifiCorp has stated in previous filings[2] that EIM transfer benefits are becoming

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[2] *In the matter of PacifiCorp d/b/a Pacific Power's 2020 Transition Adjustment Mechanism*, Docket No. UE 356, PAC/500, Brown/3 (July 15, 2019).

more predictable and the historical data illustrated in Figure 5 for the last two years shows this to be true. PacifiCorp's EIM transfer benefits are effectively close to maximum as it pertains to PacifiCorp's transmission capability in the EIM as well as the operating range of PacifiCorp's thermal and hydroelectric generation units and their ability to create additional benefits. For example, to export more volume PacifiCorp would need additional dispatchable generation capability on its system relative to today and/or additional transmission capability to adjacent balancing areas. PacifiCorp's year-over-year transfer volumes have remained relatively constant since 2018 with EIM benefit changes driven more by market price volatility due to weather conditions, gas pipeline constraints and renewable resource impacts on price.

Q. Are new EIM entrants in 2020 and 2021 projected to substantially impact PacifiCorp's forecasted EIM inter-regional transfer benefits?

A. No. The EIM footprint currently encompasses approximately 60 percent of Western Electricity Coordinating Council load and the entities joining the market in 2020 and 2021 will not increase this percentage substantially.[3] More importantly, the new entrants bring little to no transmission connectivity between themselves and PacifiCorp. With these factors combined, the projected impact to PacifiCorp's EIM transfer benefits is expected to be minimal.

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[3] Rick Adair, *BPA Lays Out Case to the Region for Joining Western Energy Imbalance Market*, WATER POWER WEST (July 9, 2019), https://www.newsdata.com/water_power_west/hydro_news/bpa-lays-out-case-to-the-region-for-joining-western/article_7d6bc08a-b3d2-11e9-8890-bbed104c473c.html.

Trend Analysis

Q. Has PacifiCorp examined alternative forecasting methodologies for EIM inter-regional transfer benefits?

A. Yes. PacifiCorp analyzed two types of trend analyses for the purpose of forecasting EIM transfer benefits. The term trend analysis as used in this testimony refers to any forecasting methodology in which past performance is the only predictor of future results.

Q. What types of trend analyses has PacifiCorp analyzed?

A. PacifiCorp has analyzed a linear trend and an exponentially weighted moving average forecast. The review of these two methods was based on stakeholder feedback in the 2020 Transition Adjustment Mechanism (TAM).[4] The linear trend is a simplified statistical forecast in which EIM transfer benefits are calculated as a function of time. The exponentially weighted moving average forecast takes the weighted average of historical data with more recent observations more heavily weighted, and uses this average as the forecast for future time periods.

Q. Has PacifiCorp found trend analysis problematic for the purpose of forecasting EIM inter-regional transfer benefits?

A. Yes. PacifiCorp has found these forecasts to be less reliable and less consistent than PacifiCorp's market fundamentals approach.

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[4] *See In the matter of PacifiCorp d/b/a Pacific Power's 2020 Transition Adjustment Mechanism, Docket No. UE 356,* Staff/300, Enright/9 (June 10, 2019); *See In the Matter of PacifiCorp d/b/a Pacific Power's 2020 Transition Adjustment Mechanism, Docket No. UE 356,* CUB/200 Gehrke/7-8 (June 10, 2019).

Q. Can you provide an example of how a trend analysis can be unreliable for the purposes of forecasting EIM inter-regional transfer benefits?

A. Yes. For example, linear trend analysis of the historical EIM transfer benefits conducted in December 2018 showed a strong upward trend in annual third quarter (Q3) benefits. However, as 2019 progressed 2019 Q3 benefits were lower than what the trend analysis forecasted. This is illustrated in Confidential Figure 6. Because the trend analysis relied solely on past performance as the predictor of future results and not on the underlying drivers of EIM transfer benefits, the trend failed to anticipate the relatively low 2019 Q3 power prices, as compared to the historical power prices observed in Q3 of 2018.

Confidential Figure 6

[redacted]

Q. Can you provide an example of how a trend analysis can be inconsistent for the purposes of forecasting EIM inter-regional transfer benefits?

A. Yes. Having a single variable, time, to produce a trend analysis can produce large variance in a forecast depending on the historical data used. For example, using the historical monthly EIM transfer benefits for the period of December 2015 to December 2016, a linear trend analysis produces a forecast for 2018 of [redacted]. If the historical data is updated to include data through December 2017, the 2019 linear trend forecast is [redacted]. Finally, if the historical data is through December 2019, a linear trend analysis produces a forecast of [redacted] for 2021 EIM transfer benefits. This is compared to the actual 2018 and 2019 EIM transfer benefits of [redacted] and [redacted], respectively. In this context, the linear trend analysis produces inconsistent results relative to historical actuals.

Q. How would an exponentially weighted moving average trend analysis forecast EIM Benefits?

A. An exponentially weighted moving average trend analysis, using the historical monthly EIM transfer benefits for the period of December 2015 to December 2016, produces a forecast for 2018 of [redacted]. If the historical data is updated to include data through December 2017, the 2019 exponentially weighted moving average forecast is [redacted]. Finally, if the historical data is through December 2019, the exponentially weighted moving average analysis produces a forecast of [redacted] for 2021 EIM transfer benefits. This is compared to the actual 2018 and 2019 EIM transfer benefits of [redacted] and [redacted], respectively. In this context, the exponentially weighted moving average produces inconsistent results relative to historical actuals.

Q. Does trend analysis have useful applications?

A. Yes. Under certain scenarios trend analysis has useful applications, such as when facing limited historical data, short time horizons, constantly evolving policy environments, or no forecasts of the underlying drivers.

Verification and Backcasting

Q. Has PacifiCorp compared its market fundamentals forecast methodology to actual EIM inter-region transfer benefits?

A. Yes. PacifiCorp has compared forecasted benefits using the market fundamentals forecast methodology to actual benefits and performed backcasts. The results of these backcasts are favorable and show that the market fundamentals forecast methodology is more accurate than the trend analyses examined above.

Q. What is a backcast?

A. In the context of EIM transfer benefits, a backcast is essentially forecasting for a known time period while only using data from before the known time period. For example, now that the Company has calculated actual 2019 EIM transfer benefits, the Company can "forecast" the 2019 EIM transfer benefits using the historical EIM transfer benefit data from January 2015–December 2018 and the actual 2019 market prices as inputs into the statistical models. By comparing the results from this 2019 backcast with the actual 2019 EIM transfer benefits, the accuracy of the models can be assessed.

Q. What backcast did PacifiCorp perform?

A. Using the current market fundamentals forecasting methodology, PacifiCorp backcasted the 2019 EIM transfer benefits using only information available before December 31, 2018, while using 2019 actual prices as the inputs for the 2019 backcast. This backcast shows estimated 2019 EIM transfer benefits of [redacted]. Using the linear trend analysis to perform the same backcast shows estimated 2019 EIM transfer benefits of [redacted]. Using the exponentially weighted moving average trend analysis to perform the same backcast shows estimated 2019 EIM transfer benefits of [redacted]. Comparing these numbers to the actual 2019 EIM transfer benefits of [redacted], the market fundamentals methodology is the most accurate. This is a favorable assessment of the market fundamentals models' annual EIM transfer benefit forecasting abilities and supports the use of this market fundamentals approach to forecasting EIM transfer benefits.

Q. In a workshop held with stakeholders in January 2019, stakeholders raised a concern about the "stationarity" of the historical EIM transfer benefits. Please explain the concept of stationarity.

A. Data is considered stationary if it does not exhibit trends or seasonal effects. Stationary time series are easier to model and some statistical modeling methods assume or require the data to be stationary.

Q. How has PacifiCorp addressed this issue?

A. To account for stakeholders' concerns on "non-stationary" data, PacifiCorp utilizes a statistical procedure known as the "Cochrane-Orcutt procedure" in all of its statistical models. This procedure reduces trends and seasonality in the data to improve the forecast. Details on this can be found in the Descriptive Statistics section of the Appendix in Confidential Exhibit PAC/201.

V. FORECASTING EIM GHG BENEFITS

Q. Please describe PacifiCorp's actual EIM GHG benefits?

A. The actual GHG benefits are the benefits received by PacifiCorp when it displaces high GHG emitting resources in the CAISO with lower GHG emitting PacifiCorp resources. GHG revenues are received for the energy dispatched to serve the CAISO's load and the associated payment to PacifiCorp for a GHG compliance cost. The Company's compliance cost is a potential requirement to procure the necessary California Carbon Allowances for the portion of the energy dispatched to serve the CAISO's load. The EIM GHG benefits are the GHG revenues less the Company's compliance costs.

Q. How does the Company forecast EIM GHG benefits?

A. The Company uses a naïve forecast, as used in the 2020 TAM,[5] with the addition of a seasonal shape. The Company's forecast of 2021 EIM GHG benefits is [redacted].

Q. What is a naïve forecast?

A. A naïve forecast is one which uses a prior period's actuals as the future period's forecast without adjustment or attempting to establish causal factors. Naïve forecasts are a type of trend analysis.

Q. Why is it appropriate to use a trend analysis in this context?

A. As discussed above there are certain scenarios in which trend analysis has useful applications. Two of those scenarios concern limited historical data and a constantly evolving policy environment. In November 2018, the CAISO implemented a new GHG policy which changed the methodology the EIM uses to allocate energy

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[5] Docket No. UE 356, PAC/500, Brown/18-21.

imported into the CAISO to meet California's GHG compliance obligations. This policy affected the marginal cost of GHG and limits useful historical data to post November 1, 2018.

Q. How did the EIM GHG forecast from the 2020 TAM[6] compare to actuals?

A. The EIM GHG forecast in the July update of the 2020 TAM was [redacted] for 2019 and 2020. This forecast performed well compared to actual December 2018–November 2019 EIM GHG benefits of [redacted], as illustrated in Confidential Figure 9.

Confidential Figure 7

[redacted]

PacifiCorp proposes to maintain this forecast methodology and continue with a naïve forecast of [redacted] for the current TAM.

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[6] Docket No. UE 356, PAC/500, Brown/18.

V. CONCLUSION

Q. Please summarize your testimony and recommendation to the Commission.

A. The methodology proposed by PacifiCorp provides the most consistent and accurate approach to calculating EIM benefits. I recommend the Commission approve PacifiCorp's EIM inter-regional transfer benefit forecast and PacifiCorp's EIM GHG benefit forecast.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 375
Exhibit PAC/201
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

EIM Inter-Regional Transfer Benefits – Statistical Model Overview

February 2020

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

REDACTED
Docket No. UE 375
Exhibit PAC/300
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Dana M. Ralston

February 2020

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

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

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I was previously 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 organizations, 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.

II. 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 2021 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony:

- Discusses how PacifiCorp has complied with the Commission's Order 20-023 which amends Order 19-351 in the 2020 TAM, allowing for testimony and a Commissioner workshop in the 2021 TAM proceeding instead of an update to the Jim Bridger fuel plan to discuss how PacifiCorp is planning for flexible fueling arrangements at the Jim Bridger plant to avoid minimum take penalties.
- Explains the primary reasons behind the changes to the total-company coal-fuel expense reflected in the 2021 TAM; and
- Provides coal pricing and background on third-party coal contracts and affiliate-owned mines.

III. COMPLIANCE WITH 2020 TAM ORDER

Q. Did the Commission include any requirements to provide updated testimony in this proceeding on the fueling arrangements at Jim Bridger in the 2020 TAM?

A. Yes, in Order 19-351 as modified by Order 20-023, the Commission required PacifiCorp to provide testimony on the fueling arrangements at Jim Bridger "in light of earlier end-of-life dates, with explanations of how PacifiCorp is planning ahead for flexible fueling arrangements to avoid minimum take penalties such as the penalties PacifiCorp incurred for lower volumes of coal deliveries at the Naughton plant in this TAM."[1]

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[1] *In the matter of PacifiCorp dba Pacific Power's 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 20-023 at 2 (Jan. 22, 2020).

Q. Has PacifiCorp complied with this requirement?

A. Yes. PacifiCorp has prepared the testimony explaining the Company's plan for avoiding minimum take penalties at the Jim Bridger plant. A Commissioner workshop has not been set up at this time; however, PacifiCorp will request one to be scheduled at the pre-hearing conference for this proceeding.

Q. How is the Jim Bridger plant fueled?

A. The Jim Bridger plant is currently fueled by two suppliers, Bridger Coal Company and Black Butte Coal Company. Bridger Coal Company is a jointly-owned, indirect subsidiary of the Jim Bridger plant owners (PacifiCorp and Idaho Power Company). Black Butte Coal Company is an unaffiliated, third-party coal supplier.

Q. Please explain how the Company has avoided minimum take penalties at the Jim Bridger Plant.

A. The current contract with Black Butte Coal Company is for an annual fixed tonnage volume that is significantly less than the total consumed tonnage at the Jim Bridger plant. The coal supply agreement with the Black Butte Coal Company supplies [redacted] of PacifiCorp's share of the Jim Bridger plant's fuel requirements for the 2021 TAM. As an indirect subsidiary of the plant owners, with no marketing operations, Bridger Coal Company coal deliveries can be flexed down to satisfy the Jim Bridger plant's requirements, as necessary. The flexibility of Bridger Coal Company allows PacifiCorp to mitigate against the risk of minimum take penalties associated with the fixed tonnage volumes from the Black Butte Coal Company.

When the current contract with Black Butte Coal Company expires at the end of 2021, [redacted]

[redacted] As part of this procurement process, PacifiCorp will continue to review the Jim Bridger plant's fueling requirements and procure the appropriate tonnage volume of coal, with flexibility and cost in mind, to mitigate the risk of incurring minimum take penalties. This fueling strategy makes it unlikely that PacifiCorp will pay any liquidated damages at the Jim Bridger plant.

IV. OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supplies for its coal plants in 2021?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 83.6 percent of its 2021 coal requirements with third-party coal supplies and 16.4 percent with coal from its captive affiliate mines. The makeup of the third-party contracts are: (1) 38.1 percent of the total coal requirement will be supplied from fixed-price contracts; (2) 19.2 percent will be supplied under variable-priced contracts that increase or decrease based on changes to producer and consumer price indices; and (3) 26.4 percent of the total coal requirement will be supplied from contracts for the Hunter and Dave Johnston plants to be negotiated in 2020 and will be 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]	16.4%
Fixed Price Contracts						
Lighthouse Resources/Black Butte	Jim Bridger			[redacted]		
Wolverine/Sufco, Dugout, Skyline	Huntington			[redacted]		
Peabody/Twentymile	Hayden			[redacted]		
Peabody/Caballo	Dave Johnston		√	[redacted]		
Arch/Coal Creek	Dave Johnston		√	[redacted]		
Subtotal Fixed Price Contracts					[redacted]	38.1%
Variable Price Contracts						
Westmoreland/Rosebud	Colstrip			[redacted]		
Westmoreland/Kemmerer	Naughton			[redacted]		
Black Hills/Wyodak	Wyodak			[redacted]		
Subtotal Variable Price Contracts					[redacted]	19.2%
Other						
Unspecified Utah Mines	Hunter			[redacted]		
Unspecified PRB Mines	Dave Johnston			[redacted]		
Total Other					[redacted]	26.4%
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 2021 TAM decreased from the level reflected in PacifiCorp's 2020 TAM?

A. Yes. As stated in the testimony of Mr. David G. Webb, total coal-fuel expense has decreased by $79.4 million—from $692.1 million in the 2020 TAM final update to $612.7 million in this initial filing in the 2021 TAM.[2] This decrease is a result of a $104.6 million volume reduction in coal-fired generation, partially offset by

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

approximately $25.2 million in higher coal prices. These variances are shown in Confidential Table 2 below.

Confidential Table 2: Coal Fuel Variance - 2021 TAM vs. 2020 TAM

Plant	Contract		Millions ($)
Price Variance			
Affiliate Mines			
Jim Bridger	Bridger Coal Company	[redacted]	
Craig	Trapper Coal	[redacted]	
Subtotal Affiliate Mines		[redacted]	
Third-Party Contracts			
Naughton	Kemmerer Coal	[redacted]	
Wyodak	Wyodak Coal	[redacted]	
Dave Johnston	Powder River Basin Coal	[redacted]	
Dave Johnston	BNSF Rail	[redacted]	
Jim Bridger	Black Butte Coal	[redacted]	
Jim Bridger	UPRR Rail	[redacted]	
Hunter	Wolverine Coal	[redacted]	
Huntington	Wolverine and Castle Valley Coal	[redacted]	
Cholla	El Segundo Coal	[redacted]	
Cholla	BNSF Rail	[redacted]	
Colstrip	Rosebud Coal	[redacted]	
Hayden	Twentymile Coal and UPRR Rail	[redacted]	
Subtotal Third-party Contracts		[redacted]	
Total Price Variance			$ 25.2
Volume Variance			
Jim Bridger		[redacted]	
Cholla		[redacted]	
Hunter		[redacted]	
Naughton		[redacted]	
Dave Johnston		[redacted]	
Other Plants		[redacted]	
Total Volume Variance			$ (104.6)
Total Coal Fuel Variance - Increase/(Decrease)			$ (79.4)

V. JIM BRIDGER FUEL SUPPLY

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company costs in the 2021 TAM.

A. Bridger Coal Company costs in the 2021 TAM are forecast to be [redacted] higher than the 2020 TAM. The cost for the base mine plan deliveries of [redacted] tons will increase by [redacted] per ton, from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, as shown in Confidential Table 3. The 2021 TAM includes a base tonnage delivery of [redacted] which is [redacted] less than in the 2020 TAM. The tonnage reduction is a major driver increasing costs in the 2021 TAM. This results in a price increase of [redacted] for the base mine plan. In the 2021 TAM, the mine is projected to deliver [redacted] than in the 2020 TAM. The reduced supplemental coal delivery results in an unfavorable price variance of [redacted]

Confidential Table 3: Jim Bridger Plant Coal Deliveries

	2021 TAM			2020 TAM			Variance			Price
	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Variance
Bridger Coal Deliveries										
Bridger Base Mine Plan	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Supplemental Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Bridger Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Black Butte Deliveries	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Jim Bridger Plant	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. Please summarize why base mine costs increase in the 2021 TAM.

A. The change is primarily due to delivering [redacted] less base tons at a cost of [redacted] an increase of [redacted] for coal inventory, [redacted] for final reclamation contributions, and [redacted] for other miscellaneous costs partially offset by a [redacted] increase in the final reclamation credit and a [redacted] decrease due to an improved heat content of the delivered coal.

Q. Please explain why the base tonnage volume decreased in the 2021 TAM.

A. Bridger Coal Company delivered [redacted] fewer base tons due to a reduction in coal consumption requirements at the Jim Bridger plant. This increased coal costs by [redacted] in the 2021 TAM.

Q. Why did coal inventory costs increase by [redacted] in the 2021 TAM?

A. The 2020 TAM assumed coal inventory would increase by [redacted] and result in a credit to coal fuel expense of [redacted]. The 2021 TAM assumes coal inventory will decrease by [redacted] and results in a debit to coal fuel expense of [redacted]. As a result of reduced plant coal consumption and subsequent coal deliveries in the 2021 TAM, Bridger Coal Company adjusted the mine plan to complete more reclamation work to effectively utilize existing resources that will be needed when underground coal production ceases after 2021. This projected mine plan change results in slightly more tons being shipped from inventory than produced.

Q. Please explain why final reclamation contributions to the trust fund increased by [redacted] in the 2021 TAM.

A. Increased final reclamation contributions to the trust fund[3] are primarily due to changing the disposal location of demolished buildings and structures associated with the underground mine, updating engineering pricing estimates, and accelerating demolition of the north wing conveyor from 2029 to 2023.

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[3] The trust fund is where the cash collected from customers is set aside to pay for the final reclamation of the mine.

Q. Please identify cost components included in the miscellaneous cost increase of [redacted].

A. Cost components included in the miscellaneous category with slight cost increases include royalties, outside services, deferred longwall, and black lung excise tax.

Q. Why did the credit for final reclamation increase by [redacted]?

A. The 2020 TAM assumed the mine would complete [redacted] of final reclamation. The 2021 TAM assumes the mine will complete [redacted] of final reclamation. The additional reclamation of [redacted] moved increases the final reclamation credit by [redacted] in the 2021 TAM.

Q. Please explain how a change in the heat content reduced costs by [redacted].

A. The average British thermal unit per pound (Btu/lb) content assumed delivered in the 2020 TAM was [redacted]. The average Btu/lb content of coal projected to be delivered in the 2021 TAM is [redacted]. The projected increase in the heat content of [redacted]. results in a favorable cost reduction of [redacted].

Q. In Order 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.[4] In this filing, does PacifiCorp adjust the price of coal from Bridger Coal Company consistent with this order?

A. Yes. In the 2021 TAM, the Company reduces Bridger Coal Company costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

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

Jim Bridger Third-Party Coal Supply

Q. What is the expected change in third-party coal prices for the Jim Bridger plant in the 2021 TAM?

A. Delivered costs for the [redacted] tons of Black Butte coal increased from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, or [redacted] overall. As stipulated in the contract, 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 2020 TAM to [redacted] per ton in the 2021 TAM. The coal price increase is approximately [redacted], or [redacted]. The Union Pacific Railroad agreement is forecast to increase by [redacted] in delivered costs.

VI. THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in overall third-party coal-supply costs in the 2021 TAM.

A. PacifiCorp expects a price variance net increase of the 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 2021.

A. The Naughton plant is supplied by the adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The coal supply agreement calculates tier-1 and tier-2 tonnage 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 tonnage 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], or [redacted], for the [redacted] tons below [redacted], an environmental shortfall payment of only [redacted] or [redacted], approximately [redacted] of the purchase price, will be owed in 2021 related to [redacted] shortfall tons on deliveries of [redacted] tons in the 2020-2021 contract year. For the six-month stub period from July 2021 through December 2021, an environmental shortfall payment of only [redacted], or [redacted], will be owed related to [redacted] shortfall tons on deliveries of [redacted] tons. 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 2020 TAM.

A. Total delivered coal cost at Naughton increased [redacted] per ton, from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM [redacted] overall), as shown in Confidential Table 4. The 2021 price forecast is based upon the settled price from the 2019 price reopener which was escalated for projected diesel fuel prices and certain price indices. The contract escalation results in a price increase of [redacted] after royalties and taxes and [redacted] as a result of reduced coal purchases for the 2020-2021 contract year. Another major driver of the price increase is a [redacted] increase in the environmental shortfall payment, from [redacted] in 2020 to [redacted] in 2021. This increase is primarily due to the stub period shortfall payment. 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 forecast tier-2 coal delivered in calendar year 2021 is [redacted] tons more than 2020.

Confidential Table 4: Naughton Contract Tonnage and Pricing

	2021 TAM			2020 TAM			Variance		
Contract Tiers	Tons	Dollars	Price	Tons	Dollars	Price	Tons	Dollars	Price
Naughton Plant									
Tier 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tier 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Coal Costs									
Environmental Shortfall	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kemmerer Btu Adjustment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Iron & Calcium Premiums	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Naughton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Btu/lb	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Wyodak

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

A. Delivered coal cost increased from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, or [redacted] overall. The cost increase is primarily the result of escalation in diesel fuel and other contract price 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 2020 TAM, or [redacted] The increase is due to an increase in coal costs of [redacted] as described in further detail below, and an increase in rail cost of approximately [redacted]

Q. Please describe the open coal position for the Dave Johnston plant included in Confidential Table 1.

A. The Dave Johnston plant is projected to consume approximately [redacted] tons in 2021; the Company currently has [redacted] tons of coal under contract for the plant resulting in an open position of [redacted] tons. The Company will solicit coal supplies from Powder River Basin (PRB) mines through a request for proposals during 2020 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 2021 TAM?

A. Arch Coal's Coal Creek mine will supply [redacted] tons and Peabody Energy's Caballo mine will supply [redacted] tons in 2021 ([redacted] of the plant's requirements). The coal price for the Dave Johnston plant's open position of approximately [redacted] tons in the 2021 TAM reflects the average 2021 forward price for PRB 8400 Btu coal of [redacted] per ton, as published in Energy Ventures Analysis Fuelcast in November 2019. The 2021 price is [redacted] higher than the 2020 PRB 8400 Btu price of [redacted] per ton that was used for the open position in the 2020 TAM, and [redacted] higher than the North Antelope Rochelle mine price of [redacted] per ton in the 2020 TAM, which will expire in December 2020. The rail cost increase of [redacted] is primarily a result of a longer rail distance for the spot coal purchases compared to the North Antelope Rochelle coal contract, which is closer to the Dave Johnston plant.

Coal Supply Agreements for the Utah Plants

Hunter

Q. Please explain how the Company's Hunter plant is supplied with coal in the 2021 TAM.

A. Historically, the primary coal supply for the Hunter plant has been provided through a coal supply agreement with Wolverine Fuels, LLC (Wolverine) formerly known as Bowie Resource Partners. The Hunter agreement with Wolverine ends in 2020. For the 2021 TAM, the pricing for coal costs is based upon a market forward price for Utah coal, as published in Energy Ventures Analysis Fuelcast in November 2019.

Q. Please describe the change in coal costs at the Hunter plant in the 2021 TAM.

A. Coal prices have increased [redacted] per ton, from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM [redacted] overall). The increase is primarily due to the estimated price for the new coal supply agreement(s) beginning in 2021.

Huntington

Q. Please describe the coal supply arrangement for the Huntington plant in 2021.

A. The primary coal supply to the Huntington plant is also provided under a requirements contract with Wolverine. This is 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 had also received coal under a coal supply agreement with Rhino Energy, LLC's Castle Valley mine. That coal supply agreement, however, ends December 31, 2020.

Q. What coal supply costs for the Huntington plant are included in the 2021 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, an overall increase of [redacted] per ton or [redacted] for the weighted average price under the Wolverine contract. The overall price per ton for the Wolverine contract increased [redacted] per ton, from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, [redacted] overall on [redacted] tons. The Wolverine contract price is higher in 2021 primarily because of transportation cost escalation.

The Castle Valley coal supply agreement expires at the end of 2020. The Castle Valley coal supply agreement was a grandfathered agreement under the Wolverine requirements coal supply agreement. The Castle Valley mine has supplied [redacted] tons of coal annually to the Huntington plant. As the Wolverine coal supply agreement is a requirements contract, the volume that was previously purchased under the Castle Valley contract will now come from the Wolverine coal supply agreement. The reduction of coal from the Castle Valley mine increased the coal costs at the Huntington plant by [redacted], as the purchase under the Wolverine coal supply agreement has a higher cost than the expired Castle Valley coal supply agreement.

Q. Does the 2021 TAM reflect Energy West pension costs?

A. Yes. As authorized under Order 15-161 in docket UM 1712, the 2021 TAM includes [redacted] for contributions to the 1974 United Mine Workers Association pension plan.[5] [redacted] is included in Huntington plant costs in the 2021 TAM, consistent with the 2020 TAM. [redacted] of the [redacted] in pension costs is included in Hunter plant costs in the 2021 TAM, consistent with the 2020 TAM.

Coal Supply Agreements for the Jointly-Owned Plants

Cholla

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

A. PacifiCorp exercised a provision in the coal supply agreement with Peabody Energy's Lee Ranch/El Segundo mine complex to terminate the contract at the end of 2020. Due to the termination of the coal supply agreement and closure of Unit 4 at the Cholla plant at the end of 2020, there are no coal costs associated with the Cholla plant in the 2021 TAM.

Craig

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

A. In 2021, 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 based upon the annual mine cost associated with the Trapper mine.

Q. Have Trapper mine costs changed from the 2020 TAM?

A. Yes. Trapper mine costs have increased [redacted] per ton, from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, a [redacted] overall price increase. The price increase is primarily due to overall mining costs at the Trapper mine.

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

Deliveries from Trapper mine have decreased [redacted] from [redacted] tons in the 2020 TAM to [redacted] tons in the 2021 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 2020 TAM to [redacted] per ton in the 2021 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 2021 TAM.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2020 TAM to [redacted] per ton in the 2021 TAM, an increase of [redacted]. PacifiCorp developed the 2021 TAM costs for the Colstrip plant based on the new coal supply agreement that was signed December 5, 2019. [redacted]

VII. CONCLUSION

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.

Docket No. UE 375
Exhibit PAC/400
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

February 2020

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

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

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.

II. 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 2021 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) including the adjustment for non-NPC Energy Imbalance Market costs and the updated amount for production tax credits identified by Mr. David G. Webb. I also provide a summary of the impact of the proposed rate change on customers' bills.

III. 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 09-274,[1] the test period for this TAM is the test year for the concurrent general rate case, which is the 12 months ending December 31, 2021.

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

A. PacifiCorp allocated forecast NPC to the customer classes based on the generation allocation factors from the concurrently filed general rate case (2021 General Rate Case). This methodology accurately allocates NPC to each customer class and ensures synchronization between the TAM and the 2021 General Rate Case. The spread of the proposed NPC to the customer classes is shown on page one of Exhibit PAC/401.

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

A. Yes. Exhibit PAC/401 shows present and proposed Schedule 201 rates and revenues. As explained by Mr. Webb, forecast NPC is subject to updates throughout this proceeding. Proposed Schedule 201 rates incorporate tariff changes proposed in the testimony of Mr. Robert M. Meredith in the 2021 General Rate Case, such as rates for

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[1] *In the matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service,* Docket No. UE 199, Order No. 09-274 (July 16, 2009).

proposed pilot programs and consolidation of lighting schedules.

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 follow the proposed rate blocks and relationships between rate blocks as proposed in the concurrent general rate case.

Q. Are changes necessary in the 2021 TAM to Schedule 205 related to TAM Adjustment for Other Revenues?

A. No. 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. As part of the Company's 2021 General Rate Case, Schedule 205 rates are proposed to go to zero as the present adjustments will now be incorporated into base rates. The tariff will be kept in place for future use.

Q. Please describe Exhibit PAC/402.

A. Exhibit PAC/402 contains the proposed revised Schedule 201.

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.

IV. 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 3.7 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/403 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 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 TAM rate change?

A. Yes. Exhibit PAC/403, 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 Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

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

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is a bill decrease of $2.95.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 375
Exhibit PAC/401
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

February 2020

PACIFIC POWER
STATE OF OREGON
Functionalized Net Power Cost Revenue Requirement
Forecast 12 Months Ended December 31, 2021
Dollars in Thousands

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		Sch 23		Sch 28		Sch 30			Sch 48T		Sch 41	Sch 15, 51
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		53, 54
1	Functionalized Generation Revenue Requirement from GRC	$723,590	$314,339	$60,890	$88	$109,490	$1,380	$67,038	$5,197	$29,460	$77,346	$46,204	$11,399	$759
2														
3	Net Power Cost Revenue Requirement	$291,975												
4	Net Power Cost Collection for Schedules not included in COS Study*	$711												
5	Net Power Cost for Schedules Included in COS Study	$291,264												
6														
7														
8	Generation Allocation Factors from GRC	100.00%	43.44%	8.42%	0.01%	15.13%	0.19%	9.26%	0.72%	4.07%	10.69%	6.39%	1.58%	0.10%
9														
10														
11	**Functionalized Net Power Cost Revenue Requirement- (Target)**	**$291,264**	**$126,530**	**$24,510**	**$35**	**$44,073**	**$555**	**$26,984**	**$2,092**	**$11,859**	**$31,134**	**$18,598**	**$4,588**	**$306**
12	Other Generation Revenue Requirement - (Target)	$432,325	$187,809	$36,380	$53	$65,418	$824	$40,053	$3,105	$17,602	$46,212	$27,605	$6,811	$454
13	Sum	$723,590	$314,339	$60,890	$88	$109,490	$1,380	$67,038	$5,197	$29,460	$77,346	$46,204	$11,399	$759

*Revenues by rate schedule as follow:

Schedule 47 Primary	$511
Schedule 47 Transmission	$280
Schedule 848 Transmission	$0
Employee Discount	($81)
Total not in study	$711

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues

Forecast 12 Months Ended December 31, 2021

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 4, Residential					
First Block kWh (0-1,000)	4,171,965,406	2.444 ¢	$101,962,835	2.170 ¢	$90,531,649
Second Block kWh (> 1,000)	1,349,161,264	3.340 ¢	$45,061,986	2.670 ¢	$36,022,606
	5,521,126,670		$147,024,821		$126,554,255
				Change	-$20,470,566
Schedule 6 TOU Pilot, untiered, per kWh				*2.292* ¢	
Employee Discount					
First Block kWh (0-1,000)	9,846,992	2.444 ¢	$240,660	2.170 ¢	$213,680
Second Block kWh (> 1,000)	4,086,037	3.340 ¢	$136,474	2.670 ¢	$109,097
	13,933,029		$377,134		$322,777
Discount			-$94,284		-$80,694
				Change	$13,589
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	875,459,662	2.708 ¢	$23,707,448	2.305 ¢	$20,179,345
All additional kWh, per kWh	252,601,527	2.007 ¢	$5,069,713	1.707 ¢	$4,311,908
	1,128,061,189		$28,777,161		$24,491,253
				Change	-$4,285,908
Primary Voltage					
1st 3,000 kWh, per kWh	1,329,489	2.623 ¢	$34,872	2.233 ¢	$29,687
All additional kWh, per kWh	756,752	1.946 ¢	$14,726	1.657 ¢	$12,539
	2,086,241		$49,598		$42,226
				Change	-$7,372
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,432,810,369	2.649 ¢	$37,955,147	2.190 ¢	$31,378,547
All additional kWh, per kWh	579,950,022	2.574 ¢	$14,927,914	2.190 ¢	$12,700,905
	2,012,760,391		$52,883,061		$44,079,452
				Change	-$8,803,609
Primary Voltage					
1st 20,000 kWh, per kWh	10,852,496	2.549 ¢	$276,630	2.139 ¢	$232,135
All additional kWh, per kWh	15,112,851	2.481 ¢	$374,950	2.139 ¢	$323,264
	25,965,347		$651,580		$555,399
				Change	-$96,181
Schedule 29 TOU Pilot, untiered, per kWh				*2.189* ¢	
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	186,649,079	2.831 ¢	$5,284,035	2.134 ¢	$3,983,091
All additional kWh, per kWh	1,077,030,703	2.454 ¢	$26,430,333	2.134 ¢	$22,983,835
	1,263,679,782		$31,714,368		$26,966,926
				Change	-$4,747,442
Primary Voltage					
1st 20,000 kWh, per kWh	12,894,541	2.800 ¢	$361,047	2.140 ¢	$275,943
All additional kWh, per kWh	84,851,350	2.420 ¢	$2,053,403	2.140 ¢	$1,815,819
	97,745,891		$2,414,450		$2,091,762
				Change	-$322,688
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	2,534,777	3.781 ¢	$95,840	2.070 ¢	$52,470
Winter, All additional kWh, per kWh	1,878,032	2.575 ¢	$48,359	2.070 ¢	$38,875
Summer, All kWh, per kWh	217,102,123	2.575 ¢	$5,590,380	2.070 ¢	$4,494,014
	221,514,932		$5,734,579		$4,585,359
				Change	-$1,149,220
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	546	3.653 ¢	$20	2.012 ¢	$11
Winter, All additional kWh, per kWh	0	2.495 ¢	$0	2.012 ¢	$0
Summer, All kWh, per kWh	38,903	2.495 ¢	$971	2.012 ¢	$783
	39,449		$991		$794
				Change	-$197
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	17,960,785	2.317 ¢	$416,151		
Off-Peak, per off-peak kWh	7,398,909	2.267 ¢	$167,733		
REV On-Peak, per on-peak kWh	*9,123,898*			2.490 ¢	$227,185
REV Off-Peak, per off-peak kWh	*16,235,796*			1.751 ¢	$284,289
	25,359,694		$583,884		$511,474
				Change	-$72,410
Transmission Voltage					
On-Peak, per on-peak kWh	8,310,064	2.176 ¢	$180,827		
Off-Peak, per off-peak kWh	6,318,086	2.126 ¢	$134,323		
REV On-Peak, per on-peak kWh	*5,262,908*			2.389 ¢	$125,731
REV Off-Peak, per off-peak kWh	*9,365,241*			1.650 ¢	$154,526
	14,628,150		$315,150		$280,257
				Change	-$34,893

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues

Forecast 12 Months Ended December 31, 2021

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	348,874,397	2.497 ¢	$8,711,394		
Off-Peak, per off-peak kWh	206,283,836	2.447 ¢	$5,047,765		
REV On-Peak, per on-peak kWh	*199,735,357*			2.609 ¢	$5,211,095
REV Off-Peak, per off-peak kWh	*355,422,876*			1.870 ¢	$6,646,408
	555,158,233		$13,759,159		$11,857,503
				Change	-$1,901,656
Primary Voltage					
On-Peak, per on-peak kWh	927,232,528	2.317 ¢	$21,483,978		
Off-Peak, per off-peak kWh	616,423,948	2.267 ¢	$13,974,331		
REV On-Peak, per on-peak kWh	*555,375,933*			2.490 ¢	$13,828,861
REV Off-Peak, per off-peak kWh	*988,280,543*			1.751 ¢	$17,304,792
	1,543,656,476		$35,458,309		$31,133,653
				Change	-$4,324,656
Transmission Voltage					
On-Peak, per on-peak kWh	554,713,687	2.176 ¢	$12,070,570		
Off-Peak, per off-peak kWh	426,309,016	2.126 ¢	$9,063,330		
REV On-Peak, per on-peak kWh	*326,571,426*			2.389 ¢	$7,801,791
REV Off-Peak, per off-peak kWh	*654,451,277*			1.650 ¢	$10,798,446
	981,022,703		$21,133,900		$18,600,237
				Change	-$2,533,663
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	8,693,135	2.037 ¢	$177,106	0.720 ¢	$62,313
	8,693,135		$177,106		$62,313
				Change	-$114,793
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	6,031,743	1.681 ¢	$101,541		
	6,031,743		$101,541		
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	13,842,798	2.649 ¢	$367,191		
	13,842,798		$367,191		
Proposed Schedule 51, Street Lighting Service, Company-Owned System					
All kWh, per kWh	20,238,069			0.720 ¢	$146,133
	20,238,069				$146,133
				Change	-$329,975
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	363,528	2.029 ¢	$7,376		
	363,528		$7,376		
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	12,045,888	0.864 ¢	$104,076	0.720 ¢	$86,730
	12,045,888		$104,076		$86,730
				Change	-$17,346
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	1,457,127	1.492 ¢	$21,740	0.720 ¢	$10,491
	1,457,127		$21,740		$10,491
				Change	-$11,249
Total before Employee Discount			**$341,280,042**		**$292,056,217**
Employee Discount			-$94,284		-$80,694
TOTAL	**13,435,239,367**		**$341,185,759**		**$291,975,523**
				Change	**-$49,210,235**
Schedule 47 Unscheduled kWh	1,910,511				
Total Forecast kWH	13,437,149,878				

Docket No. UE 375
Exhibit PAC/402
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule

February 2020

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	2.170¢			(R)
		> 1000 kWh	2.670¢			
5	Per kWh	0-1000 kWh	2.170¢			
		> 1000 kWh	2.670¢			

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).

23	First 3,000 kWh, per kWh	2.305¢	2.233¢		
	All additional kWh, per kWh	1.707¢	1.657¢		
28	All kWh, per kWh	2.190¢	2.139¢		(R) (C)

(D)

(M)
201.2

(continued)

Issued February 14, 2020
Etta Lockey, Vice President, Regulation

Effective for service on and after January 1, 2021
Docket No. UE 375

Monthly Billing (continued)

Delivery Service Schedule No.		**Delivery Voltage** **Secondary**	 **Primary**	 **Transmission**	(M) 201.1
30	All kWh, per kWh	2.134¢	2.140¢		(C)(R)
41	All kWh, per kWh	2.070¢	2.012¢		(C)(R)
47/48	Per kWh On-Peak	2.609¢	2.490¢	2.389¢	(I)
	Per kWh, Off-Peak	1.870¢	1.751¢	1.650¢	(R)

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 11 p.m. all days in the Summer months of July, August and September. Non-Summer On-Peak hours are from 5 a.m. to 9 a.m. and 4 p.m. to 12 a.m. (midnight) in the Non-Summer months of October through June. Off-Peak hours are all remaining hours. (C) | (C)

(D)
(M)
201.3

15	**Type of Lamp**	**LED Equivalent Lumens**	**Monthly kWh**	**Rate per Lamp**	(C)
	Level 1	0-5,000	19	$0.54	|
	Level 2	5,001-12,000	34	$0.97	|
	Level 3	12,001+	57	$1.63	(C)

(D)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

(D)
(C)

51

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp
Level 1	0-3,500	8	$0.20
Level 2	3,501-5,500	15	$0.37
Level 3	5,501-8,000	25	$0.62
Level 4	8,001-12,000	34	$0.84
Level 5	12,001-15,500	44	$1.08
Level 6	15,501+	57	$1.41

(C)

53 (R)

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	70	31	$0.22
High Pressure Sodium	9,500	100	44	$0.32
High Pressure Sodium	16,000	150	64	$0.46
High Pressure Sodium	22,000	200	85	$0.61
High Pressure Sodium	27,500	250	115	$0.83
High Pressure Sodium	50,000	400	176	$1.27
Metal Halide	9,000	100	39	$0.28
Metal Halide	12,000	175	68	$0.49
Metal Halide	19,500	250	94	$0.68
Metal Halide	32,000	400	149	$1.07
Metal Halide	107,800	1,000	354	$2.55

Non-Listed Luminaire, per kWh 0.720¢ (T)

54 Per kWh 0.720¢ (R) (M)
201.2

(continued)

Docket No. UE 375
Exhibit PAC/403
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

February 2020

Exhibit PAC/403
Ridenour/1

TAM Price Change

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 ENDED DECEMBER 31, 2021

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Sch No.	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) (6) + (7)	(9)	(10)	(11) (9) + (10)	(12) (9) - (6)	(13) (12)/(6)	(14) (11) - (8)	(15) (14)/(8)	
	Residential															
1	Residential	4	4	517,740	5,521,127	$628,518	$8,453	$636,972	$608,048	$8,453	$616,501	($20,471)	-3.3%	($20,471)	-3.2%	1
2	**Total Residential**			517,740	5,521,127	$628,518	$8,453	$636,972	$608,048	$8,453	$616,501	($20,471)	-3.3%	($20,471)	-3.2%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	82,822	1,130,147	$126,081	$5,748	$131,829	$121,788	$5,748	$127,536	($4,293)	-3.4%	($4,293)	-3.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,562	2,038,726	$186,682	$4,020	$190,703	$177,782	$4,020	$181,803	($8,900)	-4.8%	($8,900)	-4.7%	4
5	Gen. Svc. 201 - 999 kW	30	30	880	1,361,426	$110,812	$1,603	$112,415	$105,742	$1,603	$107,345	($5,070)	-4.6%	($5,070)	-4.5%	5
6	Large General Service >= 1,000 kW	48	48	195	3,079,837	$213,804	($8,589)	$205,215	$205,044	($8,589)	$196,455	($8,760)	-4.1%	($8,760)	-4.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	41,898	$5,249	($114)	$5,135	$5,141	($114)	$5,027	($107)	-4.1%	($107)	-4.2%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$2,222	$12	$2,234	$2,222	$12	$2,234	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	41	7,894	221,554	$25,947	($1,115)	$24,832	$24,798	($1,115)	$23,683	($1,149)	-4.4%	($1,149)	-4.6%	9
10	**Total Commercial & Industrial**			102,360	7,873,589	$670,797	$1,565	$672,362	$642,517	$1,565	$644,082	($28,280)	-4.2%	($28,280)	-4.2%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	6,045	8,693	$1,146	$214	$1,361	$1,031	$214	$1,246	($115)	-10.0%	($115)	-8.4%	11
12	Street Lighting Service Comp. Owned	50,51,52	51	1,097	20,238	$3,220	$664	$3,884	$2,890	$664	$3,554	($330)	-10.3%	($330)	-8.5%	12
13	Street Lighting Service Cust. Owned	53	53	302	12,046	$754	$154	$908	$737	$154	$891	($17)	-2.3%	($17)	-1.9%	13
14	Recreational Field Lighting	54	54	105	1,457	$121	$24	$145	$110	$24	$134	($11)	-9.3%	($11)	-7.8%	14
15	**Total Public Street Lighting**			7,549	42,434	$5,242	$1,056	$6,298	$4,768	$1,056	$5,824	($473)	-9.0%	($473)	-7.5%	15
16	**Total Sales to Ultimate Consumers**			627,649	13,437,150	$1,304,557	$11,074	$1,315,631	$1,255,333	$11,074	$1,266,407	($49,224)	-3.8%	($49,224)	-3.7%	16
17	Employee Discount			*1,036*	*13,933*	($392)	($5)	($397)	($379)	($5)	($384)	$14		$14		17
18	AGA Revenue					$2,993		$2,993	$2,993		$2,993	$0		$0		18
19	COOC Amortization					$1,727		$1,727	$1,727		$1,727	$0		$0		19
20	**Total Sales with AGA**			627,649	13,437,150	$1,308,885	$11,069	$1,319,954	$1,259,675	$11,069	$1,270,744	($49,210)	-3.8%	($49,210)	-3.7%	20

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[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), 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
TAM Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.22	$19.84	($0.38)	-1.88%
200	$29.90	$29.20	($0.70)	-2.34%
300	$39.59	$38.57	($1.02)	-2.58%
400	$49.27	$47.93	($1.34)	-2.72%
500	$58.97	$57.30	($1.67)	-2.83%
600	$68.67	$66.67	($2.00)	-2.91%
700	$78.35	$76.03	($2.32)	-2.96%
800	$88.04	$85.40	($2.64)	-3.00%
900	**$97.72**	**$94.77**	**($2.95)**	**-3.02%**
1,000	$107.42	$104.13	($3.29)	-3.06%
1,100	$120.08	$116.06	($4.02)	-3.35%
1,200	$132.74	$127.98	($4.76)	-3.59%
1,300	$145.41	$139.91	($5.50)	-3.78%
1,400	$158.07	$151.82	($6.25)	-3.95%
1,500	$170.74	$163.76	($6.98)	-4.09%
1,600	$183.41	$175.69	($7.72)	-4.21%
2,000	$234.06	$223.38	($10.68)	-4.56%
3,000	$360.71	$342.62	($18.09)	-5.02%
4,000	$487.36	$461.86	($25.50)	-5.23%
5,000	$614.00	$581.10	($32.90)	-5.36%

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

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary 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	$72	$80	$70	$78	-2.91%	-2.59%
	750	$98	$107	$95	$104	-3.17%	-2.92%
	1,000	$125	$134	$121	$130	-3.33%	-3.11%
	1,500	$179	$188	$173	$181	-3.49%	-3.33%
10	1,000	$125	$134	$121	$130	-3.33%	-3.11%
	2,000	$233	$241	$224	$233	-3.58%	-3.45%
	3,000	$340	$349	$327	$336	-3.68%	-3.59%
	4,000	$431	$440	$415	$424	-3.62%	-3.55%
20	4,000	$458	$467	$442	$451	-3.41%	-3.34%
	6,000	$640	$649	$618	$627	-3.41%	-3.36%
	8,000	$822	$831	$794	$803	-3.41%	-3.37%
	10,000	$1,004	$1,013	$970	$979	-3.41%	-3.38%
30	9,000	$967	$976	$936	$945	-3.22%	-3.19%
	12,000	$1,240	$1,249	$1,200	$1,209	-3.26%	-3.24%
	15,000	$1,513	$1,522	$1,463	$1,472	-3.29%	-3.27%
	18,000	$1,786	$1,795	$1,727	$1,736	-3.31%	-3.29%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM 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	$70	$79	$68	$77	-2.88%	-2.56%
	750	$96	$105	$93	$102	-3.15%	-2.88%
	1,000	$122	$131	$118	$127	-3.29%	-3.08%
	1,500	$175	$183	$169	$177	-3.46%	-3.30%
10	1,000	$122	$131	$118	$127	-3.29%	-3.08%
	2,000	$227	$236	$219	$228	-3.56%	-3.42%
	3,000	$331	$340	$319	$328	-3.65%	-3.56%
	4,000	$420	$429	$405	$414	-3.59%	-3.52%
20	4,000	$447	$455	$431	$440	-3.38%	-3.31%
	6,000	$624	$633	$603	$612	-3.38%	-3.33%
	8,000	$801	$810	$774	$783	-3.37%	-3.34%
	10,000	$979	$987	$946	$954	-3.37%	-3.34%
30	9,000	$943	$952	$913	$922	-3.19%	-3.16%
	12,000	$1,209	$1,218	$1,170	$1,179	-3.23%	-3.20%
	15,000	$1,475	$1,484	$1,427	$1,436	-3.25%	-3.23%
	18,000	$1,741	$1,750	$1,684	$1,693	-3.27%	-3.25%

* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	3,000	$349	$334	-4.09%
	4,500	$460	$439	-4.64%
	7,500	$684	$648	-5.21%
31	6,200	$700	$671	-4.20%
	9,300	$931	$887	-4.74%
	15,500	$1,393	$1,320	-5.28%
40	8,000	$898	$860	-4.23%
	12,000	$1,196	$1,139	-4.76%
	20,000	$1,792	$1,697	-5.30%
60	12,000	$1,339	$1,282	-4.25%
	18,000	$1,786	$1,701	-4.78%
	30,000	$2,663	$2,528	-5.06%
80	16,000	$1,774	$1,698	-4.28%
	24,000	$2,363	$2,252	-4.69%
	40,000	$3,528	$3,353	-4.94%
100	20,000	$2,209	$2,114	-4.30%
	30,000	$2,937	$2,802	-4.59%
	50,000	$4,392	$4,178	-4.87%
200	40,000	$4,324	$4,150	-4.03%
	60,000	$5,780	$5,526	-4.39%
	100,000	$8,692	$8,279	-4.75%

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* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$448	$428	-4.26%
	6,000	$549	$524	-4.63%
	7,500	$651	$619	-4.88%
31	9,300	$898	$859	-4.39%
	12,400	$1,109	$1,056	-4.74%
	15,500	$1,320	$1,254	-4.98%
40	12,000	$1,152	$1,101	-4.42%
	16,000	$1,424	$1,356	-4.77%
	20,000	$1,695	$1,611	-5.00%
60	18,000	$1,718	$1,641	-4.44%
	24,000	$2,119	$2,020	-4.67%
	30,000	$2,517	$2,397	-4.77%
80	24,000	$2,270	$2,171	-4.36%
	32,000	$2,801	$2,673	-4.54%
	40,000	$3,331	$3,176	-4.67%
100	30,000	$2,819	$2,699	-4.26%
	40,000	$3,482	$3,327	-4.47%
	50,000	$4,146	$3,955	-4.61%
200	60,000	$5,528	$5,301	-4.09%
	80,000	$6,854	$6,557	-4.33%
	100,000	$8,181	$7,813	-4.50%

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* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM 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	$2,636	$2,492	-5.47%
	30,000	$3,222	$3,045	-5.50%
	50,000	$4,393	$4,149	-5.54%
200	40,000	$4,631	$4,421	-4.54%
	60,000	$5,802	$5,526	-4.77%
	100,000	$8,145	$7,736	-5.02%
300	60,000	$6,797	$6,520	-4.07%
	90,000	$8,554	$8,178	-4.39%
	150,000	$12,067	$11,492	-4.76%
400	80,000	$8,844	$8,501	-3.88%
	120,000	$11,186	$10,711	-4.25%
	200,000	$15,870	$15,130	-4.66%
500	100,000	$10,922	$10,513	-3.74%
	150,000	$13,849	$13,275	-4.15%
	250,000	$19,705	$18,799	-4.59%
600	120,000	$12,999	$12,524	-3.65%
	180,000	$16,513	$15,839	-4.08%
	300,000	$23,539	$22,468	-4.55%
800	160,000	$17,155	$16,547	-3.54%
	240,000	$21,839	$20,967	-3.99%
	400,000	$31,208	$29,806	-4.49%
1000	200,000	$21,310	$20,571	-3.47%
	300,000	$27,166	$26,095	-3.94%
	500,000	$38,876	$37,144	-4.46%

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* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM 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	$3,159	$2,994	-5.24%
	40,000	$3,734	$3,539	-5.21%
	50,000	$4,308	$4,085	-5.19%
200	60,000	$5,693	$5,441	-4.43%
	80,000	$6,842	$6,531	-4.53%
	100,000	$7,990	$7,622	-4.61%
300	90,000	$8,387	$8,048	-4.04%
	120,000	$10,110	$9,684	-4.21%
	150,000	$11,833	$11,320	-4.34%
400	120,000	$10,986	$10,560	-3.88%
	160,000	$13,283	$12,741	-4.08%
	200,000	$15,581	$14,923	-4.22%
500	150,000	$13,597	$13,084	-3.77%
	200,000	$16,469	$15,811	-3.99%
	250,000	$19,341	$18,538	-4.15%
600	180,000	$16,208	$15,608	-3.70%
	240,000	$19,654	$18,881	-3.94%
	300,000	$23,100	$22,153	-4.10%
800	240,000	$21,430	$20,657	-3.61%
	320,000	$26,025	$25,020	-3.86%
	400,000	$30,620	$29,383	-4.04%
1000	300,000	$26,653	$25,705	-3.55%
	400,000	$32,396	$31,160	-3.82%
	500,000	$38,140	$36,614	-4.00%

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* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly 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	$193	$220	$155	$182	$197	$155	-5.42%	-10.40%	0.00%
	3,000	$289	$317	$155	$273	$288	$155	-5.43%	-8.89%	0.00%
	5,000	$481	$509	$155	$455	$470	$155	-5.43%	-7.58%	0.00%
Three Phase										
20	4,000	$385	$441	$310	$364	$395	$310	-5.43%	-10.40%	0.00%
	6,000	$578	$633	$310	$546	$577	$310	-5.43%	-8.89%	0.00%
	10,000	$963	$1,018	$310	$910	$941	$310	-5.43%	-7.58%	0.00%
100	20,000	$1,925	$2,203	$1,355	$1,821	$1,974	$1,355	-5.43%	-10.40%	0.00%
	30,000	$2,888	$3,166	$1,355	$2,731	$2,884	$1,355	-5.43%	-8.89%	0.00%
	50,000	$4,813	$5,091	$1,355	$4,551	$4,705	$1,355	-5.43%	-7.58%	0.00%
300	60,000	$5,775	$6,609	$3,410	$5,462	$5,922	$3,410	-5.43%	-10.40%	0.00%
	90,000	$8,663	$9,497	$3,410	$8,193	$8,652	$3,410	-5.43%	-8.89%	0.00%
	150,000	$14,438	$15,272	$3,410	$13,654	$14,114	$3,410	-5.43%	-7.58%	0.00%

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

Pacific Power
TAM Monthly 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	$280	$307	$155	$265	$280	$155	-5.36%	-8.80%	0.00%
	4,000	$373	$400	$155	$353	$368	$155	-5.36%	-8.00%	0.00%
	5,000	$466	$493	$155	$441	$456	$155	-5.36%	-7.50%	0.00%
Three Phase										
20	6,000	$559	$613	$310	$529	$559	$310	-5.36%	-8.80%	0.00%
	8,000	$746	$426	$310	$706	$736	$310	-5.36%	72.86%	0.00%
	10,000	$932	$426	$310	$882	$912	$310	-5.36%	114.32%	0.00%
100	30,000	$2,797	$3,066	$1,344	$2,647	$2,796	$1,344	-5.36%	-8.80%	0.00%
	40,000	$3,730	$3,998	$1,344	$3,530	$3,679	$1,344	-5.36%	-8.00%	0.00%
	50,000	$4,662	$4,931	$1,344	$4,412	$4,561	$1,344	-5.36%	-7.50%	0.00%
300	90,000	$8,392	$9,198	$3,400	$7,942	$8,389	$3,400	-5.36%	-8.80%	0.00%
	120,000	$11,189	$11,995	$3,400	$10,589	$11,036	$3,400	-5.36%	-8.00%	0.00%
	150,000	$13,986	$14,792	$3,400	$13,236	$13,683	$3,400	-5.36%	-7.50%	0.00%

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

Pacific Power
TAM 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	$26,465	$25,360	-4.17%
	500,000	$37,659	$35,818	-4.89%
	700,000	$48,853	$46,276	-5.28%
2,000	600,000	$52,496	$50,287	-4.21%
	1,000,000	$72,633	$68,952	-5.07%
	1,400,000	$93,921	$88,767	-5.49%
6,000	1,800,000	$152,251	$145,624	-4.35%
	3,000,000	$216,114	$205,069	-5.11%
	4,200,000	$279,977	$264,515	-5.52%
12,000	3,600,000	$303,174	$289,920	-4.37%
	6,000,000	$430,901	$408,811	-5.13%
	8,400,000	$558,628	$527,702	-5.54%

Notes:	Present	Proposed
On-Peak kWh	62.84%	35.98%
Off-Peak kWh	37.16%	64.02%

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

Pacific Power
TAM 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		Percent Difference
		Present Price	Proposed Price	
1,000	300,000	$25,049	$24,142	-3.62%
	500,000	$35,449	$33,938	-4.26%
	700,000	$45,849	$43,734	-4.61%
2,000	600,000	$49,622	$47,809	-3.65%
	1,000,000	$68,172	$65,150	-4.43%
	1,400,000	$87,872	$83,641	-4.81%
6,000	1,800,000	$143,226	$137,786	-3.80%
	3,000,000	$202,327	$193,261	-4.48%
	4,200,000	$261,427	$248,735	-4.86%
12,000	3,600,000	$285,094	$274,215	-3.82%
	6,000,000	$403,295	$385,163	-4.50%
	8,400,000	$521,496	$496,111	-4.87%

Notes:	Present	Proposed
On-Peak kWh	60.07%	35.98%
Off-Peak kWh	39.93%	64.02%

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

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	500,000	$35,199	$33,803	-3.97%
	700,000	$44,886	$42,933	-4.35%
2,000	1,000,000	$67,259	$64,467	-4.15%
	1,400,000	$85,533	$81,626	-4.57%
6,000	3,000,000	$199,762	$191,388	-4.19%
	4,200,000	$254,587	$242,863	-4.60%
12,000	6,000,000	$397,369	$380,621	-4.21%
	8,400,000	$507,019	$483,572	-4.62%

Notes:	Present	Proposed
On-Peak kWh	56.54%	33.29%
Off-Peak kWh	43.46%	66.71%

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