PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

April 3, 2023

VIA ELECTRONIC FILING

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

Re: Advice No. 23-008/UE 420—PacifiCorp's 2024 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, 2024.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2024 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The proposed tariff sheets listed in Section B below are provided in Ms. Ridenour's Exhibit PAC/302. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Ramon J. Mitchell, Manager, Net Power Costs
- James Owen, Senior Vice President, Environmental, Fuels, and Mining
- Judith M. Ridenour, Specialist, Pricing and Cost of Service

B. Tariff Sheets

Tariff Sheet	Schedule	Title
Eighteenth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Eighteenth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Eighteenth 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 652,000 customers and would result in an overall annual rate increase of approximately $163.8 million or 9.5 percent. Residential customers using 900 kilowatt-hours per month would see an average monthly bill increase of $9.58 per month as a result of this change.

D. Correspondence

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

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

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

By regular mail: Data Request Response Center
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 2023 TAM proceeding, docket UE 400. Confidential material in support of the filing has been provided to parties under Order No. 16-128. Highly confidential material in support of this filing has been provided to parties under Order No. 23-120.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

Cc: UE 400 Service List

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **2024 Transition Adjustment Mechanism** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 3rd day of April, 2023.

Carrie Meyer

Carrie Meyer
Adviser, Regulatory Operations

REDACTED
Docket No. UE 420
Exhibit PAC/100
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Ramon J. Mitchell

April 2023

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 Company).

A. My name is Ramon J. Mitchell, 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 Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have held various positions in the regulation, merchant, and transmission departments. After a brief departure from the Company, in 2021 I returned to the Company as Manager, Net Power Costs. In my current role I am responsible for leading and overseeing various efforts associated with the Company's net power costs (NPC) filings.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Public Utility Commission of Oregon (Commission), as well as commissions in California, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. I present the Company's proposed 2024 Transition Adjustment Mechanism (TAM) NPC. Specifically, my testimony:

- Defines NPC and summarizes the content of the filing;
- Describes the major cost drivers in the 2024 TAM;

- Describes the NPC change in the 2024 TAM compared to the final NPC in docket UE 400, the 2023 TAM;
- Describes modeling changes the Company is proposing in this TAM filing;
- Provides an update on provisions from the 2021 TAM;
- Discusses the information ordered by the Commission in the last TAM Order; and
- Provides details on the calculation of the Transition Adjustment and the Consumer Opt-Out Charge.

Q. Please identify the other Company witnesses supporting the 2024 TAM.

A. Two additional Company witnesses provide testimony supporting the Company's filing. James Owen, Vice President, Environmental, Fuels and Mining, provides testimony supporting the coal fuel costs and the prudence of the new coal supply agreements included in the 2024 TAM. 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 THE COMPANY'S 2024 TAM FILING

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.[1]

Q. Please explain how the Company calculates NPC.

A. The Company calculates NPC for a future test period based on a forecast using Aurora, which is a production cost model. Aurora simulates the operation of the Company's power system on an hourly basis and provides an hourly forecast of NPC for the future test period.

Q. Has the Company proposed any modeling changes in the 2024 TAM?

A. Yes. The Company is proposing the following modeling change in addition to modeling changes proposed in the 2023 TAM:

- Trapped energy will be appropriately substituted for curtailment of generation to reflect actual operations.

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

A. Yes. In compliance with the TAM Guidelines, the Company provided notice of changes to the Company's modeling of NPC in the 2024 TAM. This notice was provided on February 28, 2023 and is included as Exhibit PAC/105.

Q. What modeling improvements were implemented in the 2023 TAM?

A. The following modeling improvements were implemented in the 2023 TAM:

[1] *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).

- Wholesale sales market caps were based on the four-year historical average of short-term firm balancing and spot sales, differentiated by on and off-peak hours. This was completed consistent with the Commission's continued review of this issue as identified in Order No. 21-379;[2]
- The planned maintenance outages were based on the Company's budgeted outage plan;[3]
- The day-ahead/real-time (DA/RT) price adders were changed to a percentage of market prices;[4]
- The regulating reserve requirement was updated to reflect higher reliability and resource adequacy standards consistent with the Company's operations;[5]
- The maximum generating capacity of certain thermal generating units were updated to reflect actual generating capacity during the summer months; and[6]
- Inclusion of startup costs for gas-fired units.[7]

Q. Are the modeling improvements from the 2023 TAM implemented in this filing?

A. Yes, the modeling improvements from the 2023 TAM have been implemented in this year's filing.

Q. What inputs were updated for this filing?

A. The Company updated all inputs to the 2024 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, the official

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[2] *In the Matter of PacifiCorp d/b/a Pacific Power 2022 Transition Adjustment Mechanism*, Docket No. UE-390, Order No. 21-379 at 28 (Nov. 1, 2021).
[3] *In the Matter of PacifiCorp d/b/a Pacific Power 2023 Transition Adjustment Mechanism*, Docket No. UE-400, PAC/100, Wilding/34-35 (Mar. 1, 2022).
[4] *Id.* at 35-36.
[5] *Id.* at 33-34; Docket No. UE-400, PAC/300, MacNeil/4-30.
[6] Docket No. UE-400, PAC/100, Wilding/37-38.
[7] *Id.* at 38-39.

forward price curve (OFPC) market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities.

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

A. The Company's filing uses the OFPC dated December 31, 2022.

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

A. Yes. In accordance with the current TAM Guidelines, the Company's reply update will incorporate the most recent OFPC that is available at the time the update is prepared. 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. This ensures that the most up-to-date market information is used in the forecast, providing a more accurate estimate of NPC for the test period.

Q. Please provide background on the Company's 2024 TAM filing.

A. The TAM is an annual filing that the Company makes to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2024 TAM also includes test period forecasts for: (1) incremental benefits and costs related to the Company's participation in the energy imbalance market (EIM) with the California Independent System Operator (CAISO); and (2) renewable energy production tax credits (PTCs).

Q. What is the total-company NPC in the TAM for calendar year 2024?

A. The forecasted normalized total-company NPC for calendar year 2024 is approximately $2.642 billion.[8] This is approximately $665 million higher than the total-company forecast NPC of approximately $1.977 billion in the 2023 TAM. Further details on the total-company NPC for 2024 are provided in Exhibit PAC/102.

Q. What is the increase to the Oregon-allocated NPC and the impact to Oregon rates?

A. As shown in Exhibit PAC/101, there is an increase to Oregon-allocated NPC of approximately $255 million and an increase in PTCs (decrease to rates) of approximately $7.8 million. After adjusting for the variance from loads, the 2024 TAM results in an increase to Oregon rates of approximately $164 million. Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis. As explained in the testimony of Company witness Ridenour, the 2024 TAM results in an overall average rate increase of approximately 9.5 percent.

Q. Does the proposed rate increase for the 2024 TAM reflect changes in Oregon load since the 2023 TAM?

A. Yes. The 2024 load forecast used in the Company's calculation of NPC reflects an increase in Oregon load compared to the 2023 forecast loads in the 2023 TAM. Due to the increase in Oregon load, the Company anticipates it will collect approximately $84 million more than what was approved in the 2023 TAM, reducing the overall requested rate increase.

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[8] Exhibit PAC/101, Mitchell/1, line 35.

Q. Please explain how the EIM inter-regional and greenhouse gas benefits are treated in the 2024 TAM.

A. The Company's initial filing includes a forecast of both the inter-regional transfer benefits and greenhouse gas (GHG) benefits from participation in the EIM. The expected incremental inter-regional EIM transfer benefits relative to the optimized NPC modeled by Aurora are reflected as a reduction to the NPC forecast. The total-company inter-regional EIM transfer benefits included in the 2024 TAM is [redacted], a [redacted] of [redacted] in benefits from the 2023 TAM. The total-company EIM GHG benefits is [redacted], a [redacted] from the 2023 TAM.

IV. DISCUSSION OF MAJOR COST DRIVERS IN THE TAM

Q. The 2024 TAM indicates a $665 million increase in NPC, on a total-company basis, from the 2023 TAM. Please elaborate on the drivers for this increase.

A. There are four main factors that drive the increase in the 2024 TAM as compared to the 2023 TAM and each of these factors impact the accuracy of the 2023 TAM forecast (i.e., what the 2023 TAM forecast would now be if updated with current values): 1) The power, natural gas and coal prices for calendar year 2023 have increased by an average of 31 percent, 20 percent and 12 percent respectively since the 2023 TAM; 2) The NPC forecast in the 2023 TAM excluded the impacts of the Washington Cap and Invest Program and also excluded the impacts of the Ozone Transport Rule (OTR); 3) the hedges in the 2023 TAM were favorable to the current calendar year 2023 market prices from the OFPC used in this filing; and 4) the calendar year 2023 Oregon load projections used to calculate the 2023 TAM NPC were substantially lower than the current calendar year 2023 load projections.

Q. Please elaborate on how the increase in power, gas and coal prices for calendar year 2023 is relevant to the NPC increase.

A. The 2023 TAM used a November 8, 2022 vintage OFPC to set the price expectations for calendar year 2023. Compared to current calendar year 2023 price expectations from the December 31, 2022 vintage OFPC, average power market prices across the Mid-Columbia and Palo Verde trading hubs increased by 31 percent and average natural gas market prices across the Sumas and Opal trading hubs increased by 20 percent. Additionally, average coal prices increased by 12 percent.

This implies that the 2023 TAM NPC forecast is an under-forecast relative to this latest OFPC and relative to current coal prices and presents the first support that an updated 2023 NPC comparison forecast would be *higher* than this 2024 TAM NPC forecast.

Q. Please elaborate on how exclusion of the Washington Cap and Invest Program and exclusion of the OTR is relevant to the NPC increase.

A. The 2023 TAM NPC forecast did not include any costs associated with the Washington Cap and Invest Program which began in 2023. Furthermore, the 2023 TAM NPC forecast did not include any costs associated with the OTR which begins in 2023.

This implies that the 2023 TAM NPC forecast is an under-forecast relative to what it would have been had these costs been included and presents the second support that an updated 2023 NPC comparison forecast would be *higher* than this 2024 TAM NPC forecast.

Q. Please elaborate on how favorable hedges in the 2023 TAM NPC forecast is relevant to the NPC increase.

A. Hedging transactions and associated costs are designed to limit the risks and variability associated with market exposure and to provide rate stability; they are not economic optimization transactions. When hedges lower NPC, it is coincidental, not a guaranteed outcome or foregone conclusion. Therefore, the appropriate comparison between the 2023 TAM NPC forecast and the 2024 TAM NPC forecast is to assume that there are neither economic benefits nor costs from hedging transactions. With this assumption, in conjunction with the current calendar year 2023 market prices from the OFPC used in this filing, an updated 2023 NPC comparison forecast would be substantially higher.

This implies that the 2023 TAM NPC forecast is an under-forecast relative to what it would have been had the hedging transactions shown neither economic benefit nor cost, at the prevailing OFPC, and presents the third support that an updated 2023 NPC comparison forecast would be *higher* than this 2024 TAM NPC forecast.

Q. Please elaborate on how an increase in the calendar year 2023 Oregon load projections is relevant to the NPC increase.

A. On a dollar basis, higher load equates to higher NPC. If the 2023 TAM NPC forecast reflected the current calendar year 2023 Oregon load projections, then the 2023 TAM NPC forecast would be higher on a total-company basis.

This implies that the 2023 TAM NPC forecast, *on a dollar basis*, is an under-forecast relative to what it would have been had the load been updated with current expectations and presents the fourth support that an updated 2023 NPC comparison forecast would be *higher* than this 2024 TAM NPC forecast.

Q. After consideration of these four factors which support increases in the 2023 NPC forecast for appropriate comparison to this filing's 2024 NPC forecast, what is the appropriate 2023 NPC for comparison purposes?

A. After adjusting for the four aforementioned factors[9], the 2023 NPC comparison forecast updates to approximately $2.628 billion total-company. Additionally, the 2024 Jim Bridger gas conversion and the 2024 Klamath river hydroelectric projects' deconstruction are *not* accounted for in this $2.628 billion. For accurate cross-year comparisons, the NPC impacts of these 2024 operational changes,[10] when accounted for incremental to the $2.628 billion, raises the 2023 NPC comparison forecast to $2.774 billion total-company; and in this context, the 2024 TAM NPC forecast of $2.642 billion is a *decrease* compared to this updated 2023 NPC comparison forecast.

V. NPC VALIDATION

Q. Is $2.642 billion a reasonable forecast for total-company NPC?

A. Yes. There are three layers to consider when assessing the 2024 NPC forecast: 1) historical actual NPC and the associated trend that is proportionate to regional power market prices; 2) the extrapolation of this trend using the 2024 OFPC; and 3) five

[9] The OTR assumptions used to recreate the 2023 NPC forecast are based on the OTR assumptions used in the 2024 NPC forecast.
[10] Totaling $146 million total-company as discussed in more detail, below in my testimony.

upcoming, new, and substantial impacts to NPC that are not captured in the historical data or trend.

Q. Regarding the first layer, what does the historical actual NPC show?

A. There is a clear and demonstrable relationship between actual NPC and regional power market prices. First consider Table 1 below which shows, the actual 2020 NPC, the actual 2021 NPC, the actual 2022 NPC and the 2023 TAM NPC forecast of 2023.

Table 1: Historical NPC

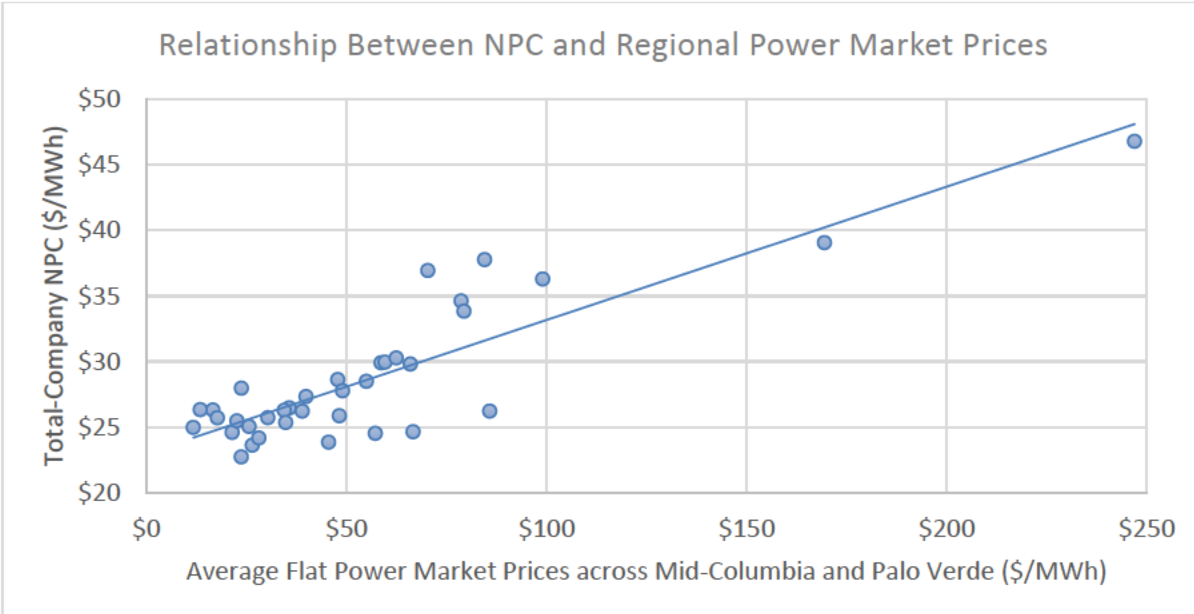
NPC Type	Total Company NPC ($)
2020 Actual	1,511,314,189
2021 Actual	1,714,607,879
2022 Actual	2,040,736,242
2023 *Forecast (2023 TAM)*	1,977,454,591

There are two items of note: 1) the 2023 TAM NPC forecast of calendar year 2023 at $1.977 billion is substantially under-forecast (i.e., the forecast is less than the expected actuals) as discussed in detail in Section IV of my testimony above; and 2) within the actuals, there is a clear upward trend in NPC.

Q. Regarding the second layer, please elaborate on this upward trend in NPC and the associated extrapolation.

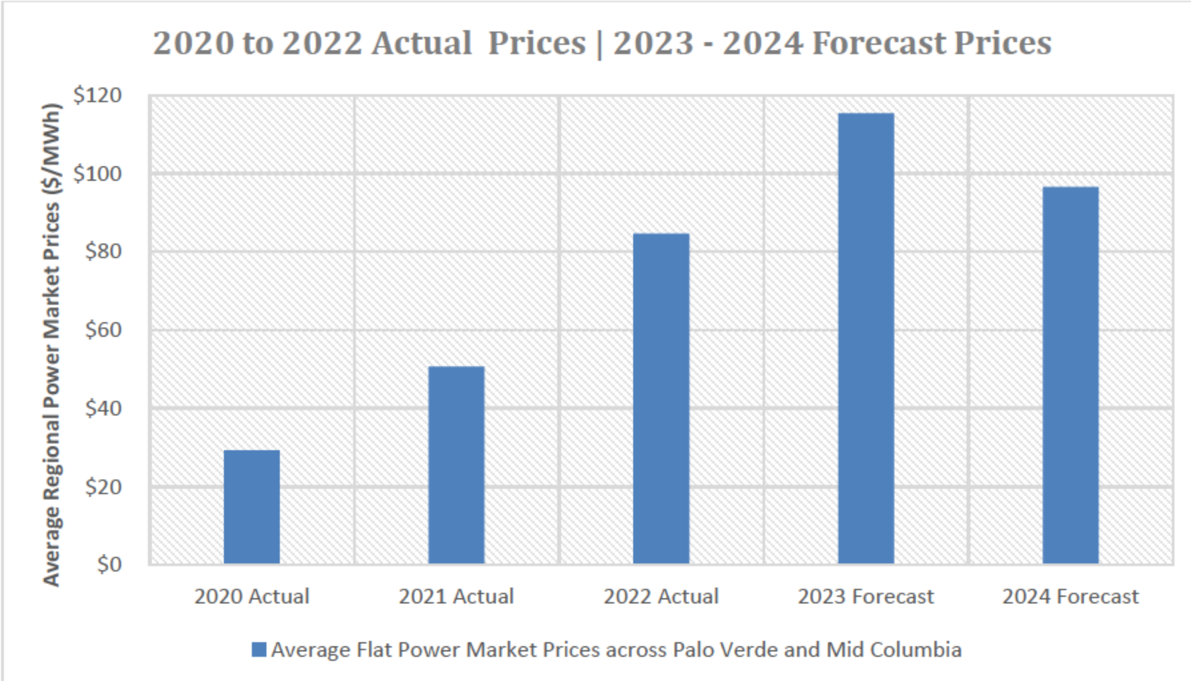
A. When actual NPC is broken down to the monthly granularity, it is observed that there is a proportionate relationship between actual NPC and regional power market prices. This relationship is illustrated in Figure 1 below.

Figure 1: Relationship Between NPC and Power Market Prices



To establish a baseline reference for what a reasonable 2024 NPC forecast (without any new operational changes or federal/state environmental compliance requirements) might be, we can extrapolate the relationship between regional power market prices and NPC as shown in the figure above. This extrapolation suggests 2024 NPC of $2.201 billion. Figure 2 below illustrates year-over-year changes in actual and forecast regional power market prices that provide context for the *actual* NPC increases in Table 1 and context for the extrapolation of 2024 NPC (absent any changes in operations or environmental compliance requirements) at $2.201 billion.

Figure 2: Actual and Forecast Power Market Prices



Q. Regarding the third layer, please elaborate on some of the new and upcoming operational changes and environmental compliance requirements not captured in the historical data or the trend.

A. Historical NPC and the corresponding relationship with regional power market prices have not captured any of the cost impacts of five substantive changes to the 2024 landscape: 1) the expansion and revision of the Environmental Protection Agency's (EPA) OTR on nitrogen oxides' (NO_x) emissions limits to encompass all thermal generation in the states of Wyoming and Utah; 2) the new program in Washington state (the Washington Cap and Invest Program) that essentially taxes GHG emissions through required purchases of greenhouse gas allowances (impacting the Chehalis gas-fired plant located in Washington state); 3) the conversion of the Jim Bridger power plant's units 1 and 2 from coal-fired to gas-fired units; 4) the removal of four hydroelectric projects along the Klamath river; and 5) coal supply limitations impacting all Company coal-fired plants in the state of Utah. These five changes and their individual impacts to NPC are described in more detail, below in my testimony. In aggregate they increase NPC by $456 million on a total-company basis.

Q. How do these three layers demonstrate the reasonableness of the NPC forecast?

A. The historical actual NPC in combination with the proportionate relationship between NPC and regional power market prices suggest that, absent any changes in environmental compliance requirements or operations, $2.201 billion is a reasonable NPC forecast for 2024. After layering on an additional $456 million to account for the aforementioned upcoming environmental compliance requirements and operational changes, which are not reflected in the historical data, a reasonable benchmark for 2024 NPC becomes $2.656 billion which is 0.5 percent above the proposed $2.642 billion total-company NPC. This difference of 0.5 percent results from the use of a relatively simple trend analysis as a reference for the 2024 NPC (absent environmental compliance requirements or operations changes) as compared to the more detailed production-cost modeling within Aurora.

VI. DISCUSSION OF NPC CHANGES IN THE TAM

Q. Please generally describe the changes in NPC compared to the 2023 TAM.

A. The increase in NPC is driven by a reduction in wholesale sales revenue, increased purchased power expense, increased natural gas fuel expense, and increased wheeling and other expense. This is partially offset by a reduction in coal fuel expense. Table 2 for dollars and Table 3 for energy illustrate the changes in total-company NPC by category from the 2023 TAM NPC to the 2024 TAM NPC while Confidential Figure

3 illustrates the generation changes in Table 3 as a generation resource stack visualization.

Table 2: NPC Reconciliation Dollars

Net Power Cost Reconciliation		
	($ millions)	**$/MWh**
OR 2023 TAM Forecast[1]	**1,996**	**32.30**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	137.0	
Purchased Power Expense	159.2	
Coal Fuel Expense	(87.9)	
Natural Gas Fuel Expense	427.1	
Wheeling and Other Expense	10.8	
Total Change to NPC	**646.2**	
OR 2024 TAM Forecast	**2,642**	**39.65**

[1] This forecast does not include the impact of the OTR, the Washington Cap and Invest Program or the settled unspecified monetary adjustment of $18.9 million total-company.

Table 3: NPC Reconciliation Energy

Net Power Cost Reconciliation		
	MWh	**$/MWh**
OR 2023 TAM Forecast	**61,802,663**	**32.30**
Change to Net System Load:		
Wholesale Sales Decrease	2,946,233	
Purchased Power Increase	3,880,420	
Coal Generation Decrease	(10,065,681)	
Natural Gas Generation Increase	8,876,822	
Other Generation Decrease	(815,569)	
Total Change to Net System Load	**4,822,225**	
OR 2024 TAM Forecast	**66,624,888**	**39.65**

Confidential Figure 3: 2023 vs 2024 Generation Resource Stack Comparison

[redacted]

Q. Please explain the increase in purchased power expense.

A. The purchased power expense increases in tandem with increased purchased power volumes due to lower coal generation to comply with the OTR emissions limits in conjunction with limited coal supply availability in the state of Utah (discussed further in the testimony of Company witness Owen), the decrease in generation at the Chehalis plant due to the Washington energy tax, the outage for Jim Bridger units 1 and 2 to complete the gas conversion and expectations of low hydroelectric generation. I explain these individual drivers in more detail, below in my testimony.

Q. Please explain the decrease in coal fuel expense and the increase in natural gas fuel expense.

A. Coal generation in both Wyoming and Utah is subject to the new emissions limits in the OTR, resulting in a decrease to coal generation and associated decrease to coal fuel expense. Furthermore, coal supply availability has diminished, resulting in lowered coal generation availability, lower coal generation, and lower coal fuel expense, in that order. Additionally, the gas conversion of Jim Bridger units 1 and 2 remove two generating units out of the coal fuel expense category, further decreasing coal fuel expense. Inversely, natural gas generation increases due to the gas conversion of Jim Bridger units 1 and 2 which adds two generating units into the natural gas fuel expense category, increasing natural gas fuel expense. Natural gas generation, and corresponding natural gas fuel expense, also increases due to increased generation at other gas units to meet load and reserve obligations left behind after the decrease in coal and hydroelectric generation.

Q. Please explain the decrease in wholesale sales revenue and the increase in wheeling and other expense.

A. With decreased net generation, excess capacity available for offer into the wholesale power markets decreases and therefore wholesale sales volume and the corresponding wholesales sales revenue decreases in tandem. Wheeling expense increases relative to the forecast in the 2023 TAM based on increases in the historical wheeling expenses supporting 2022 actual purchased power volumes.

VII. ENVIRONMENTAL REQUIREMENTS AND OPERATIONS CHANGES

Q. What environmental compliance requirements or operations changes are forecast to have a substantial impact on 2024 NPC?

A. There are six, which are: 1) the expansion and revision of the OTR on NO_x emissions limits to encompass all thermal generation in the states of Wyoming and Utah; 2) the establishment of a *de-facto* tax impacting generation at Chehalis; 3) the conversion of Jim Bridger units 1 and 2 from coal-fired to gas-fired units; 4) expectations of lower hydroelectric generation; 5) the construction of the Gateway South transmission line (a portion of the Energy Gateway transmission expansion), which relieves transmission limitations on the output of wind generation in Wyoming;[11] and 6) coal supply limitations impacting all Company coal-fired plants in the state of Utah.

The Ozone Transport Rule

Q. Please generally describe the OTR.

A. The EPA is in the process of establishing annual limits on the amount of NO_x that can be emitted by certain states including Wyoming and Utah. These NO_x limits apply during the ozone season, which spans May 1st to September 30th. They apply to Utah starting in 2023 and are assumed to apply to Wyoming starting in 2024. The final rule has been issued, but there remains uncertainty regarding the implementation, and a decision on the inclusion of Wyoming in 2024 has been deferred.

[11] The cost impacts of the Energy Gateway transmission expansion are not included in the analysis that demonstrates the reasonableness of the Company's proposed NPC for the test period because they are already captured in the historical data that supports that reasonability analysis.

Q. How did you implement the OTR in the NPC forecast?

A. Functionally, NOx emissions limits are no different from coal contract volumetric limits, transmission capacity limits, generator capacity limits, or any of the other myriad limits inherent to the Company's operations. All Company operated gas-fired and coal-fired generation units in the states of Wyoming and Utah are now constrained by specific NO_x emissions limits across the ozone season. These unit level NO_x emissions limits are directly input into Aurora, which natively allows for this type of modeling.

Q. There is uncertainty around the implementation of the OTR, how will you manage this uncertainty in the NPC forecast?

A. Pending further clarifying guidance from the EPA the Company proposes to refresh the NPC forecast with updated data on this environmental compliance requirement during the normal update schedule, during the pendency of this case, up to and inclusive of the final filing in November.

Q. What is the impact to NPC of this environmental compliance requirement?

A. Assuming that both Utah and Wyoming are subject to the OTR in 2024, the impact of this adjustment is an increase of $202 million on a total-company basis or $58 million on an Oregon-allocated basis. This increase is driven by increased market purchases to cover the generation reduction.

Assuming that only Utah is subject to the OTR in 2024, the impact of this adjustment is an increase of $31 million on a total-company basis or $8.8 million on an Oregon-allocated basis.

The Washington Cap and Invest Program

Q. How does the Washington Cap and Invest Program impact the Company's load service in Oregon?

A. The Washington Cap and Invest Program requires that the Company purchase GHG allowances for any GHG emissions output within the state of Washington for export outside the state of Washington. The only source of GHG emitting energy owned by the Company in the state of Washington is the Chehalis gas-fired plant. For all energy exported out of Washington from the Chehalis plant, there is an associated GHG cost proportionate to the energy exported. Therefore, for all energy allocated to Oregon from the Chehalis plant, there is an incremental dollar-per-megawatt-hour ($/MWh) cost based on the GHG allowance price for the test period.

Q. What is the GHG allowance price applied to the Chehalis plant for this test period?

A. The GHG allowance price is currently forecasted as [redacted] for calendar year 2024 based off the auction clearing price as of March 7, 2023.[12] The Company proposes to refresh the NPC forecast with updated data, inclusive of more granular prices, on this environmental compliance requirement during the normal update schedule, during the pendency of this case, up to and inclusive of the final filing in November.

[12] WASHINGTON DEPARTMENT OF ECOLOGY, *Washington Cap-and-Invest Program Auction #1 Summary Report* (Mar. 7, 2023) *available at* https://apps.ecology.wa.gov/publications/documents/2302022.pdf.

Q. How are the Washington Cap and Invest Program costs similar to other costs or revenues that have been previously included in NPC?

A. The Washington Cap and Invest Program is a *de-facto* tax program that assesses a charge per megawatt-hour (MWh) of energy produced from certain types of resources located in Washington state. From a cost perspective, the impact of this program on the Company's service territory is identical to: 1) the impact of the current EIM GHG benefits received as a result of California's Cap and Trade program; 2) the impact of the current EIM inter-regional transfer benefits received from the CAISO's EIM, which reduces EIM export benefits by assessing a GHG related energy tax on inter-regional transfers into the state of California from the Company's thermal generators; and 3) Wyoming's wind tax.

Q. What is the impact to NPC of this environmental compliance requirement?

A. The impact of this adjustment is an increase of $73 million on a total-company basis or $21 million on an Oregon-allocated basis. This increase is driven by increased market purchases to cover the generation reduction.

Jim Bridger Power Plant's Natural Gas Conversion – Units 1 and 2

Q. Please describe what is taking place at Jim Bridger units 1 and 2.

A. Jim Bridger units 1 and 2 are proposed to be converted to gas-fired units. Currently, these two units are coal-fired.

Q. Why are Jim Bridger units 1 and 2 being converted to gas?

A. Emissions requirements imposed by the EPA required the installation of a selective catalytic reduction system to reduce NO_x emissions from Jim Bridger units 1 and 2 for continued coal-fired operations past December 31, 2023. Gas conversion was identified as a more economically viable option in the long-term analysis of the integrated resource planning process partially driven by a need for the Company to retain as much upward-dispatchable capacity as possible.

Q. What is the impact to NPC of this conversion?

A. There are two impacts. The first impact is the result of replacing the coal-fired units with similarly sized gas-fired units, all other things equal. The impact of this adjustment is an increase of $92 million on a total-company basis or $26 million on an Oregon-allocated basis. This increase is driven by the fact that natural gas fuel is more expensive than coal fuel. The second impact is the result of the outage period necessary to accomplish the gas conversion. With both units being out of service from [redacted] there is a $42 million increase on a total-company basis or $12 million on an Oregon-allocated basis. This increase is driven by increased market purchases to cover the generation loss.

Q. Why are the NPC impacts of the Jim Bridger units' gas conversion separated into two components?

A. The first impact is permanent and starts with a counterfactual in which the units are instantaneously converted to gas on January 1, 2024, this counterfactual is necessary due to the EPA's requirement that coal-fired operations cease on December 31, 2023. The second impact is temporary (the gas conversion process is a one-off event) and presents an isolated impact of the outage in 2024, which examines the effect of replacing gas generation with market purchases.

Hydroelectric Generation Reduction

Q. How much has hydroelectric generation decreased between the 2023 TAM and this current filing?

A. The forecast for calendar year 2024 hydroelectric generation has decreased by approximately 569,000 MWh (16 percent) as compared to the 2023 TAM filing.

Q. Why has hydroelectric generation decreased?

A. The pending removal of the four Company-operated hydroelectric projects[13] along the Klamath river drives this decrease. These projects total approximately 180 megawatts of capacity and will cease operations by the end of 2023.

Q. What is the impact to NPC of these hydroelectric projects' removal?

A. The impact of this adjustment is an increase of $53 million on a total-company basis or $15 million on an Oregon-allocated basis. This increase is driven by increased market purchases to cover the generation reduction.

Gateway South Transmission Project

Q. What is the Gateway South Transmission Project?

A. As part of the Company's Energy Gateway transmission expansion, the Company is building a 500-kilovolt high-voltage transmission line, known as Gateway South, extending from the Aeolus substation in southeastern Wyoming into the Clover substation in central Utah.

Q. What are the qualitative benefits of this Gateway South transmission build?

A. The Gateway South Project will meet load growth, provide increased reliability, and improve operational flexibility in conjunction with future generation resources,

[13] J.C. Boyle, Copco 1, Copco 2 and Iron Gate hydroelectric projects.

including renewable energy. Specifically, it will allow for the release of "trapped energy" from wind resources in Wyoming. This concept of trapped energy is discussed in more detail, below in my testimony.

Q. What is the impact to NPC of the Gateway South transmission build?

A. The line is forecast to go into service in October of 2024, resulting in a decrease in NPC of $19 million on a total-company basis or $5.5 million on an Oregon-allocated basis, primarily driven by increased wind generation.

Coal Supply Limitations

Q. What limitations are there on projected coal supply in this 2024 TAM?

A. Please refer to the testimony of Company witness Owen who elaborates on projected limitations to the availability of coal in the state of Utah.

Q. What is the impact to NPC of this coal supply limitation?

A. The impact of this limitation is an increase of $108 million on a total-company basis or $31 million on an Oregon-allocated basis. This increase is driven by increased market purchases to cover the generation reduction.

VIII. MODELING IMPROVEMENTS

Q. In addition to the modeling improvements proposed in last year's filing, is the Company incorporating any additional modeling improvements into this year's TAM?

A. Yes. The Company is proposing the following modeling improvement:

- Trapped energy will be appropriately substituted for curtailment of generation to reflect actual operations.

Trapped Energy

Q. Please explain the Company's trapped energy concept.

A. Primarily, trapped energy is a modeling concept only and does not exist in actual operations. It represents any excess generation that cannot be used to serve load due to transmission constraints or system-level oversupply. Because of limited transmission and the need for supply and demand to always be balanced, the trapped energy is captured within a modeled trapped energy zone and serves "pseudo load" that is regulated by a "pseudo generator" with an infinite ramp rate ("pseudo" - *i.e.*, the load and generation in the trapped energy zone are also modeling constructs that do not exist in actual operations).

Q. Why was the trapped energy modeling concept necessary in the old Generation and Regulation Initiative Decision Tools (GRID) model?

A. Conceptually, the trapped energy zones allow for a feasible model solution in the event of an inability to maintain the supply/demand balance when there is excess supply. However, the primary function of trapped energy zones in prior GRID NPC simulations was to allow for Company-owned PTC eligible wind to be modeled with a reasonable degree of accuracy. Due to an inability in GRID to model resources with a negative dispatch cost (representative of PTCs, in the case of wind), these wind resources could not provide the proper price signal to the model and therefore could not be accurately represented within GRID's resource stack. As a work-around, the wind resources were simulated as must run resources and all excess wind generation within a transmission constrained area was funneled into a trapped energy zone.

Q. How was energy in the trapped energy zone valued?

A. In the 2023 TAM, the Company valued trapped energy at 25 percent of market prices, which led to overstated sales revenue. Since this trapped energy concept does not exist in actual operations, the value of trapped energy should be zero.

Q. How does Aurora eliminate the need for trapped energy zones?

A. Aurora eliminates the need for trapped energy zones by allowing for wind curtailment while recognizing the PTC benefits that produce an implied negative dispatch cost. The NPC simulation in Aurora places the wind resources at the bottom of the resource stack and allows the model to dispatch the wind resources downwards when there is more energy from the wind resources than there is transmission to move the energy to load or when the ramp capability of dispatchable resources is unable to follow sharp hour-to-hour ramps in wind generation. This reflects how wind resources are actually operated and actually dispatched downwards in actual operations.

Q. Please quantify the NPC impact of allowing wind to be curtailed in similar fashion as actual operations.

A. The impact of allowing for realistic wind curtailment is an increase of $14 million on a total-company basis or $4.1 million on an Oregon-allocated basis, driven by: 1) a reduction in pseudo-wholesale sales revenue earned from the sales of energy derived from a modeling construct that does not exist in actual operations; and 2) incremental wind curtailments needed to maintain the supply/demand balance within a transmission congested region when considering that sharp hour-to-hour ramps in wind generation cannot be completely balanced by relatively slow ramping coal units present in the region.

Q. Is it still necessary to value the trapped energy zone at zero percent of market prices after allowing for wind curtailments?

A. No, there would be no impact. After allowing for appropriate wind curtailment, the trapped energy modeling construct has been removed. That is to say, there are no more trapped energy zones modeled in this filing.

IX. COMPLIANCE WITH TAM ORDERS

Q. The 2021 TAM Order describes certain actions that need to be taken prior to the 2024 TAM filing. What are those actions?

A. In Order No. 20-392, the Commission adopted the stipulation reached between the parties.[14] The Company agreed to the following:

- Performing an informational model run that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants (to be provided in 15-day workpapers).

Q. Has the Company performed this informational model run?

A. Yes. The informational model run will be provided with the 15-day workpapers for this filing.

Q. The 2023 TAM Order describes certain actions that need to be taken prior to the 2024 TAM filing. What are those actions?

A. In Order No. 22-389, the Commission adopted the stipulation reached between the

[14] *See In the matter of PacifiCorp dba Pacific Power's 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).

parties.[15] The Company agreed to the following:

- PacifiCorp will make best efforts to provide to parties a benchmarking study that uses inputs from 2019 actuals on February 1, 2023.

Q. Did the Company provide the benchmarking study on February 1, 2023 as requested in the 2023 TAM Order?

A. Yes. The study was provided and is attached to this testimony as Exhibit PAC/106. The relevant workpapers are also provided concurrently with this filing.

Q. Were there other items that needed to be followed-up on from the 2023 TAM Order?

A. Yes. The following Table 4 lists some of the information that was ordered or agreed to by joint stipulation in the 2023 TAM Order and describes where it has been provided:

Table 4: Information Requested in Order No. 22-389

Order/Stipulation Requirement	Details
PacifiCorp shall explain further how dispatch of generation resources is changing materially year over year in response to the changing utilization of coal plants from 2021 to 2022 and 2022 to 2023 and discuss the drivers of the change in resource mix in 2023.	Provided in Section X of this testimony.
PacifiCorp shall provide a unit-by-unit comparison of the PacifiCorp portion of the projected coal delivery in tons, coal burned, energy generation in MWh, and coal cost by month and in total between the respective TAM forecast years of 2021 to 2022 and 2022 to 2023.	Provided in the concurrent workpapers that accompany this filing.
PacifiCorp affirms that the Schedule 296 calculations used to calculate the Consumer Opt-Out Charge, including all supporting work papers, will be provided consistent with the TAM guidelines, 30 days after filing the TAM.	Will be provided in the 30-day workpapers for this filing.

[15] *See In the matter of PacifiCorp dba Pacific Power's 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 (Oct. 25, 2022).

As long as there are coal-fired Jim Bridger units in Oregon rates and they are fueled with coal from Bridger Coal Company, PacifiCorp will provide a copy of the updated annual Bridger Coal Company mine plan along with any alternatives that were also evaluated for PacifiCorp in future TAM filings.	These are provided in PacifiCorp's workpapers associated with this filing.
For the 2024 TAM proceeding, PacifiCorp is directed to provide projections for its Hunter contract, including an analysis of the appropriate minimum take and overall thermal fleet usage in multiple scenarios.	This is discussed in Section IV of Company witness Owen's testimony.
PacifiCorp to hold a workshop with Staff and parties within a reasonable time after PacifiCorp's execution of the CSA and prior to the 2025 TAM.	As discussed in Company witness Owen's testimony, this workshop will be held before the 2025 TAM.
PacifiCorp shall within 30 days of the issuance of this order provide a current version of the "Contract Minimum" table provided in docket UE 375 in response to ALJ Bench Request 3.2 and in docket UE 390 in response to ALJ Bench Request 1. PacifiCorp shall file an updated version of this table in its 2024 TAM filing, as well.	PacifiCorp submitted this table on November 21, 2022 in docket UE 400. A revised version is provided as Exhibit PAC/205 to Company witness Owen's testimony.

X. CHANGE IN GENERATION RESOURCE DISPATCH

Q. Please explain the Commission's first order as tabulated above in Table 4.

A. In the 2023 TAM Order, the Commission ordered the Company to explain further how dispatch of generation resources is changing materially year over year in response to the changing utilization of coal plants from 2021 to 2022 and 2022 to 2023 and discuss the drivers of the change in resource mix in 2023.

Q. Please explain your interpretation of the Commission's order.

A. From a cause-and-effect perspective, variable power costs and the associated resource stack drives generation resource dispatch, as opposed to coal generation dispatch driving all other generation resource dispatch. From this perspective, the Company understands the Commission's order as directing the Company to explain how all generation resource dispatch is changing materially year over year in response to variable power costs and the associated resource stack from 2021 to 2022 and 2022 to 2023, from the perspective of the relevant TAMs.

In the context of changing generation resource dispatch, the concept of changes in resource mix is related to the changes in generation resource dispatch produced by different generation technology types as opposed to the installed capacity of different generation technology types. From this perspective, the Company understands the Commission's order as directing the Company to discuss the drivers of the change in generation resource dispatch as it pertains to the MWh production of different generation technology types forecasted in the 2023 TAM as compared to the 2022 TAM.

Q. Please explain how generation resource dispatch changes year over year from 2021 to 2022 and 2022 to 2023.

A. Changes in generation dispatch are a function of the prevailing resource stack when considering that customer load is served based on the principles of least cost dispatch. Any year-over-year change in generation resource dispatch is correlated with changes in the order and dispatch of the resources in the resource stack. This order is based upon the resources' marginal costs (incremental variable power costs) and the dispatch is dependent on the resources' technology type and prevailing operational constraints.

Q. Elaborate further on the resource stack and how it relates to the principles of least cost dispatch.

A. Customer load is served through a combination of generation resources and market resources based on least cost dispatch principles. Least cost dispatch principles establish a resource stack wherein the lowest marginal cost resource is at the bottom of the stack (whether bottom or top is subject to the reader's visualization preferences) and as one moves up the stack the resources become more expensive, with the highest marginal cost resource at the top of the stack. In the context of NPC, the marginal cost of a resource is a measure of the variable cost incurred to serve the next MWh of customer load. Additionally, each resource within the resource stack has a dispatch that determines the resource's size within the stack. This dispatch is dependent on the resource's technology type and prevailing operational constraints. Customer load is satisfied first by the resource at the bottom of the stack and then by going up the stack until the total of the dispatch equals the total customer load.

Q. Please anchor this discussion on the resource stack with an illustration of and commentary on the 2021 TAM resource stack.

A. In the context of generation resource dispatch, Confidential Figure 4 below illustrates the annual aggregate generation resource stack from the 2021 TAM projected to serve customer load in 2021.

Confidential Figure 4: 2021 Resource Stack

[redacted]

Confidential Figure 4 above illustrates the generation resource stack segmented by technology type, with the exception of long-term firm purchases, with each segment differentiated and labeled by annual aggregate average prices. The resource stack illustrates the following: 1) at the bottom of the resource stack, 11.5 million MWh of generation dispatch from Company owned renewables at $0/MWh, the least-cost resources on the system; 2) 0.3 million MWh of generation dispatch from Company owned geothermal at an average price of $17/MWh, differentiated from the renewable portion of the stack due to non-zero costs; 3) 31.5 million MWh of generation dispatch from coal at an average price of $21/MWh; 4) 11.0 million MWh of generation dispatch from gas at an average price of $24/MWh; and 5) 10.3 million MWh of generation dispatch from long-term firm purchases (qualifying facilities (QF), purchase power agreements (PPA), etc.) at an average price of $50/MWh. The size of each segment corresponds to the generation dispatch.

Q. How do operational constraints impact the size (generation dispatch) of each segment of the resource stack?

A. It depends on the technology type: 1) The generation dispatch of company owned renewables (inclusive of geothermal) are based primarily on natural production (subject to transmission constraints and supply/demand constraints) and their generation dispatch is variable and, absent curtailments or reservoir storage at hydroelectric facilities, out of the Company's control; 2) long-term firm purchases are primarily wind, solar or hydro QFs or PPAs and their generation dispatch is also based on natural production and outside of the Company's control; 3) coal and gas generation dispatch is limited primarily by reserve requirement constraints, as discussed in more detail further below in my testimony, and other operational considerations such as ambient temperature constraints and transmission constraints.

Q. Regarding the Company's interpretation of the Commission's order, please explain how all generation resource dispatch is changing materially year over year in response to variable power costs.

A. Confidential Figure 5 below compares the 2021 TAM generation resource stack with the 2022 TAM generation resource stack. Across the two years, gas prices increased substantially and this drove a reduction in gas generation dispatch. All other generation dispatch remained relatively constant but for a slight decrease in renewable generation dispatch. The net decrease in gas generation dispatch and renewable generation dispatch was mostly offset by market transactions.

Confidential Figure 5: 2021 and 2022 Resource Stack

[redacted]

Confidential Figure 6 below compares the 2022 TAM generation resource stack with the 2023 TAM generation resource stack. Across the two years the Company transitioned to the Aurora model and incorporated higher regulating reserve requirements to reflect higher operating, reliability and resource adequacy requirements.[16] This increased operational constraint, within the context of a new model that incorporates ramp constraints to maintain the supply-demand balance, reduced the generation availability and associated generation dispatch of coal to: 1) allow for gas to balance sharp hour to hour variations in renewable generation dispatch; and 2) hold additional regulation reserves. Inversely, gas generation dispatch increased to allow for supply-demand balancing, inclusive of the aforementioned variations in renewable generation dispatch, with increases in renewable generation dispatch and long-term firm purchases' generation dispatch offsetting the net decrease across coal and gas generation dispatch.

[16] Docket No. UE 400, PAC/100, Wilding/33.

Confidential Figure 6: 2022 and 2023 Resource Stack

[redacted]

Q. Please discuss the drivers of the change in generation resource dispatch as it pertains to the production of different generation technology types forecasted in the 2023 TAM as compared to the 2022 TAM.

A. With changes in dispatch by technology type being equivalent to changes in energy resource mix and with the generation resource stacks in Confidential Figure 6 above as a guide, please refer to the explanation above of how generation resource dispatch (broken out by technology type) changed materially year over year, from 2022 to 2023.

Q. In the 2023 TAM Order, the Commission notes that "[i]n the company's initial testimony in the 202[3] TAM, PacifiCorp stated that there was a decline in coal generation and volume. In reply testimony, PacifiCorp stated that there was an increase in coal generation as part of the company's optimized dispatch for its system."[17] How do you explain this discrepancy?

A. In reply testimony, the Company's statement on coal generation increase[18] was in response to a claim made by the Sierra Club in their initial testimony which reads, "PacifiCorp projects higher coal generation compared to the 2022 TAM."[19] At first glance, it would appear that the Sierra Club's assertion of higher coal generation may have been deliberately misleading based on the clear and unambiguous data in the 2023 TAM NPC workbooks, which showed lower coal generation on aggregate in the 2023 TAM initial filing as compared to the 2022 TAM final filing as plainly stated in the Company's initial testimony.[20]

[17] Order No. 22-389.
[18] Docket No. UE 400, PAC/600, Mitchell/83 (June 22, 2022).
[19] Docket No. UE 400, Sierra Club/100, Burgess/13 (May 25, 2022).
[20] Docket No. UE 400, PAC/100, Wilding/13.

In that context, the Company interpreted the Sierra Club's response as poorly worded as opposed to deliberately misleading and assumed their reference to higher coal generation as being specific to the **one** plant which showed higher coal generation compared to the 2022 TAM. This plant [redacted] amongst the Company's coal fleet.

Q. In the isolated context of the Company's response to the Sierra Club's poorly worded statement on higher coal generation, how does "increased coal generation as part of the system's optimized dispatch"[21] not contradict "lower coal generation volume at the Company's coal plants"?[22]

A. Interpreting the Sierra Club's reference to higher coal generation as specific to the [redacted], increased coal generation from the least cost coal resource as part of the system's approach to optimized dispatch is not an unexpected result. This explains the Company's statement on an increase in coal generation.

However, the Company then noted that "[t]his approach optimizes the dispatch of the Company's existing system in the most economic, or least-cost, manner **while accounting for constraints** [emphasis added]."[23] Within the broader context of the Company's initial testimony, it was emphasized that the regulating reserve requirement constraint in the 2023 TAM was increased to "reflect the higher operating, reliability and resource adequacy requirements PacifiCorp is currently subject to."[24] Consequently, "[d]ue to the increased resource adequacy standard,

[21] Docket No. UE 400, PAC/600, Mitchell/83.
[22] Docket No. UE 400, PAC/100, Wilding/13.
[23] Docket No. UE 400, PAC/600, Mitchell/84.
[24] Docket No. UE 400, PAC/100, Wilding/33.

resource generation availability to meet load is reduced".[25] This explains the Company's statement on a decline in coal generation, which was observed in aggregate.

XI. PRODUCTION TAX CREDITS

Q. Please describe the treatment of renewable energy PTCs in the 2024 TAM.

A. The 2024 TAM includes changes in projected levels of PTCs. Confidential Exhibit PAC/103 shows the forecast level of PTCs for 2024 compared to the level of PTCs established in the 2023 TAM. The forecast value of Oregon-allocated PTCs for the 2024 test period is approximately $80.4 million, which is higher than the $72.6 million included in the 2023 TAM, resulting in a decrease to the 2024 TAM of $7.8 million.

Q. How are PTCs calculated for the 2024 TAM?

A. The 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 2.9 cents per kilowatt-hour (kWh) for pre-2022 projects or the current PTC rate of 3.0 cents per kWh for projects placed in service after 2022, and then grossing-up for taxes.

Q. Please describe the capacity, capacity factors, generation and PTCs for the wind projects in the 2024 TAM.

A. As seen in Confidential Table 5 below, on a total-company basis, the total-company-owned wind capacity is 2,198 MW. Total forecast generation on a total-company

[25] Docket No. UE 400, PAC/100, Wilding/34.

basis is 7,178,397 MWh. The total tax-adjusted PTCs on an Oregon-allocated basis are $80.4 million.

Confidential Table 5: Company-Owned Wind Projects Generation and PTC Data

[redacted]

Q. Why is the aggregate wind generation in the 2024 TAM lower than the aggregate wind generation in the 2023 TAM?

A. In a review of the 2021 Power Cost Adjustment Mechanism, Commission Staff observed that the Company's wind generation was substantially over-forecast (i.e., more wind generation in the forecast as compared to the wind generation that materialized in reality). After a review of the TAM filings from calendar years 2016 to 2022 the Company found that all seven years, but one, had an over-forecast of wind generation in each final TAM filing as illustrated below in Table 6. The trapped energy modeling enhancement, as discussed above in my testimony, now shows the 2024 forecast[26] to be more accurate, within 2.0% of 2022 actual wind generation[27] as compared to the historical average 11.0% over-forecast of wind generation.

Table 6: Wind Forecast - Variance to Actual

Period	Actual (MWh)	Forecast (MWh)	Over Forecast/ (Under Forecast)
2024 Counterfactual[26]		7,089,449	
2023		7,573,819	
2022	6,949,590	7,545,687	8.6%
2021	6,389,267	7,064,532	10.6%
2020	3,404,418	3,312,773	(2.7%)
2019	1,952,733	2,857,240	46.3%
2018	2,700,550	2,874,335	6.4%
2017	2,400,316	2,874,335	19.7%
2016	2,711,238	2,869,840	5.8%
Historical Result[28]:	11.0%	Over-Forecast	
2024 vs 2022	2.0%	Over-Forecast	
2022 Wind Year	4.3%	Above Normal Wind Year	

XII. TRANSITION ADJUSTMENT AND CONSUMER OPT-OUT CHARGE

Q. What is the Transition Adjustment?

A. The transition adjustment[29] is the difference between the estimated market value of the electricity that is freed up when a customer chooses to leave Cost-Based Supply Service for Direct Access versus the Company's regulated price. The estimated market value of the freed-up electricity is determined by running two NPC forecasts –

[26] A modeling sensitivity which keeps constant within the 2024 forecast the wind and transmission assets as of 2022 for the purposes of comparing to the 2022 actual wind generation.
[27] Wherein 2022 was also an above normal wind year: i.e., the wind blew 4.3% harder compared to the most recent four-year average.
[28] The historical aggregate 11.0% over-forecast excludes calendar year 2021.
[29] *Pacific Power Tariff Schedule 294*, *First Revision of Sheet 294-1*, P.U.C. OR No. 36, *available at* https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/294_Transition_Adjustment.pdf.

one forecast with the Company serving the Direct Access Consumer and one forecast with the Company not serving the Direct Access Consumer. The difference between the two forecasts is analyzed to calculate the impact on the Company's total system. The impacts are then used to determine the Weighted Market Value of the energy, which is then compared to the Customer's energy-only tariff schedule rate.

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 the Company 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.[30]

Q. Has the Company identified any errors in the calculation of the Transition Adjustments and the Consumer Opt-Out Charge?

A. Yes, the Company has identified a discrepancy in the calculation of the Weighted Market Value of the energy (weighted price) for Transition Adjustments and Consumer Opt-Out Charges, as used in Schedules 294, 295 and 296. Currently, the spreadsheet calculations of these weighted prices do not include the DA/RT price adjustment used by the Company in its NPC forecasts. This creates a discrepancy in the weighted price spreadsheet calculations whereby the NPC forecasts that form the foundation of the weighted price spreadsheet calculations are subject to the DA/RT

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[30] *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).

price adjustment, but the weighted price spreadsheet calculations that derive the Transition Adjustments and Consumer Opt-Out Charges are not subject to the DA/RT price adjustment.

Q. Please explain the DA/RT price adjustment

A. The DA/RT price adjustment is used to better reflect system balancing costs that are not fully captured in NPC forecasts. This adjustment indicates a deviation of actual power market prices available to the Company in real operations from the historical monthly trading-hub-indexed power market prices. To better reflect the market prices available to the Company when it transacts in the power market, the Company calculates separate prices for forecast system balancing sales and for forecast system balancing purchases. These prices account for the historical price differences between the Company's purchases and sales as compared to the monthly average power market-indexed prices. Without consideration of intra-month modifications to the DA/RT price adjustment which are not relevant to this discussion, the DA/RT modeling enhancement was approved by the Commission in the 2016, 2017, and 2018 TAM proceedings.[31]

Q. Please explain how the weighted price spreadsheet calculations use power market prices.

A. In the determination of Transition Adjustments or Consumer Opt-Out Charges, all company generation resources are marked-to-market at the monthly granularity in a spreadsheet calculation. More specifically, instead of determining the Transition

[31] *In re PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015); *In re PacifiCorp, dba Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016); *In re PacifiCorp, dba Pac. Power 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 5-9 (Nov. 1, 2017).

Adjustments or Consumer Opt-Out Charges using the true marginal costs of the Company's generation resources, the marginal costs are adjusted to be the weighted average of forecast monthly trading-hub-indexed power market prices (the OFPC) and the marginal cost itself. After the DA/RT price adjustment was approved by the Commission, the company adjusted the OFPC within the NPC forecast model, but did not adjust the OFPC within the weighted price spreadsheet calculation.

Q. How has the Company remedied this oversight?

A. The Company has now aligned across its calculations by correcting for this oversight through application of the monthly granularity DA/RT price adjustment to the weighted price spreadsheet calculation.

XIII. COMPANY SUPPLY SERVICE ACCESS CHARGE

Q. What is the Company Supply Service Access Charge?

A. If a new customer elects new load direct access and then subsequently switches to standard offer or cost-based service, resulting in an increase to rates for existing cost-of-service customers of more than 0.5 percent, the consumer electing to switch to standard offer service or cost-based service will be subject to a four-year forward looking rate adder, the Company Supply Service Access Charge. The 0.5 percent assessment is a reasonable threshold for the Company Supply Service Access Charge that represents a material and significant impact to customers and was acknowledged by the Commission at a public meeting on February 26, 2019.[32]

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

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.

XIV. COMPLIANCE WITH TAM GUIDELINES

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

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

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

A. Yes.

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 Aurora project and workpapers concurrently with this initial filing. Specifically, the Company provided the NPC report workbook and the Aurora project.

Q. Did the Company 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. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 420
Exhibit PAC/101
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Oregon-Allocated Net Power Costs

April 2023

PacifiCorp
CY 2024 TAM
Initial Filing

			Total Company					Oregon Allocated	
Line no		ACCT.	UE-400 CY 2023 - Final Filing	TAM CY 2024 - Initial Filing	Factor	Factors CY 2023	Factors CY 2024 Initial Filing	UE-400 CY 2023 - Final Filing	TAM CY 2024 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	6,381,695	-	SG	26.002%	28.701%	1,659,353	-
3	Existing Firm UPL	447	-	-	SG	26.002%	28.701%	-	-
4	Post-Merger Firm	447	556,906,202	426,328,887	SG	26.002%	28.701%	144,805,420	122,362,385
5	Non-Firm	447	-	-	SE	24.920%	28.515%	-	-
6	**Total Sales for Resale**		563,287,897	426,328,887				146,464,773	122,362,385
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	59,530,582	22,795,100	SG	26.002%	28.701%	15,479,000	6,542,514
10	Existing Firm Demand UPL	555	9,126,863	9,531,665	SG	26.002%	28.701%	2,373,145	2,735,722
11	Existing Firm Energy	555	171,504,893	71,888,724	SE	24.920%	28.515%	42,739,259	20,499,156
12	Post-merger Firm	555	1,094,540,292	1,389,718,118	SG	26.002%	28.701%	284,599,752	398,868,641
13	Secondary Purchases	555	-	-	SE	24.920%	28.515%	-	-
14	Other Generation Expense	555	-	-	SG	26.002%	28.701%	-	-
15	**Total Purchased Power**		1,334,702,630	1,493,933,607				345,191,156	428,646,032
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	23,886,724	22,898,000	SG	26.002%	28.701%	6,210,969	6,572,048
19	Existing Firm UPL	565	-	-	SG	26.002%	28.701%	-	-
20	Post-merger Firm	565	124,541,723	134,214,173	SG	26.002%	28.701%	32,383,041	38,521,355
21	Non-Firm	565	6,893,033	9,027,449	SE	24.920%	28.515%	1,717,753	2,574,188
22	**Total Wheeling Expense**		155,321,479	166,139,622				40,311,763	47,667,591
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	635,260,287	547,388,163	SE	24.920%	28.515%	158,307,751	156,088,389
26	Fuel Consumed - Coal (Cholla)	501	-	-	SE	24.920%	28.515%	-	-
27	Fuel Consumed - Gas	501	19,326,688	156,802,484	SE	24.920%	28.515%	4,816,238	44,712,416
28	Natural Gas Consumed	547	396,871,314	692,508,768	SE	24.920%	28.515%	98,900,886	197,469,703
29	Simple Cycle Comb. Turbines	547	13,620,689	7,592,963	SE	24.920%	28.515%	3,394,295	2,165,143
30	Steam from Other Sources	503	4,484,106	4,440,902	SE	24.920%	28.515%	1,117,446	1,266,329
31	**Total Fuel Expense**		1,069,563,084	1,408,733,280				266,536,615	401,701,979
32									
33	TAM Settlement Adjustment*		(18,844,704)	-		As Settled		(4,900,000)	-
34									
35	**Net Power Cost (Per Aurora)**		1,977,454,591	2,642,477,623				500,674,760	755,653,217
36									
37	Oregon Situs NPC Adustments		(1,091,313)	(905,561)	OR	100.000%	100.000%	(1,091,313)	(905,561)
38	**Total NPC Net of Adjustments**		1,976,363,278	2,641,572,061				499,583,447	754,747,655
39									
40	Production Tax Credit (PTC)		(279,202,594)	(280,217,247)	SG	26.002%	28.701%	(72,597,592)	(80,426,290)
41	**Total TAM Net of Adjustments**		1,697,160,684	2,361,354,814				426,985,855	674,321,365
42									
43								Increase Absent Load Change	247,335,510
44									
45							Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-400	$426,985,855	
46							$ Change due to load variance from UE-400 forecast	83,509,234	
47							2024 Recovery of NPC (incl. PTC) in Rates	$510,495,090	
48									
49								**Increase Including Load Change**	**$ 163,826,275**
50									
51	*TAM Settlement Filing UE-400 - Agreed to decrease Oregon-allocated NPC by							Add Other Revenue Change	-
52	$4,900,000.								
53								**Total TAM Increase/(Decrease)**	**$ 163,826,275**

Docket No. UE 420
Exhibit PAC/102
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Costs Report

April 2023

2024 TAM Initial NPC Report

	Total	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
								$					
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hurricane Sale	$ 2,228	$ 2,228	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper Revenue	$ 353,394	$ 26,267	$ 23,495	$ 27,826	$ 16,228	$ 20,336	$ 22,380	$ 55,884	$ 55,044	$ 38,231	$ 24,244	$ 19,233	$ 24,228
PSCo_Sale	$ 11,561,948	$ 654,964	$ 942,025	$ 1,003,664	$ 713,460	$ 576,640	$ 950,064	$ 881,326	$ 2,979,360	$ 846,560	$ 805,283	$ 598,562	$ 610,040
Total Long Term Firm Sales	$ 11,917,570	$ 683,459	$ 965,520	$ 1,031,490	$ 729,688	$ 596,976	$ 972,444	$ 937,210	$ 3,034,404	$ 884,791	$ 829,527	$ 617,795	$ 634,268
Short Term Firm Sales													
Borah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Balancing Sales													
COB	$ 110,236,223	$ 11,315,280	$ 7,272,976	$ 3,851,833	$ 3,478,687	$ 4,558,061	$ 7,276,434	$ 8,822,872	$ 8,851,106	$ 14,719,899	$ 13,014,529	$ 12,273,302	$ 14,801,245
Four Corners	$ 56,805,275	$ 10,314,140	$ 2,467,089	$ 3,639,025	$ 2,679,208	$ 1,922,071	$ 3,055,469	$ 4,596,368	$ 2,855,467	$ 7,020,428	$ 5,163,045	$ 3,634,975	$ 9,457,989
Mead	$ (456,626)	$ (262,255)	$ 10,663	$ 39,627	$ 94,211	$ 5,214	$ (223,084)	$ 92,249	$ (185,555)	$ 456,491	$ 52,832	$ 20,717	$ (557,736)
Mid Columbia	$ 217,672,551	$ 30,658,264	$ 20,510,683	$ 13,683,677	$ 6,599,723	$ 6,052,613	$ 3,821,434	$ 28,031,330	$ 29,924,670	$ 24,163,549	$ 16,200,904	$ 15,592,383	$ 22,433,320
Mona	$ 10,085,529	$ 1,775,356	$ 1,872,382	$ 361,898	$ 178,893	$ 85,224	$ 685,348	$ 548,074	$ 376,190	$ 3,420,512	$ 343,677	$ 94,618	$ 343,357
NOB	$ 16,560,664	$ 1,614,373	$ 1,410,564	$ 1,265,927	$ 804,081	$ 392,411	$ 1,096,869	$ 1,671,008	$ 2,868,575	$ 2,033,442	$ 1,183,270	$ 1,270,471	$ 949,672
Palo Verde	$ 3,507,700	$ 291,937	$ 186,986	$ 66,718	$ 21,962	$ 17,755	$ 321,263	$ 650,096	$ 1,228,871	$ 309,659	$ 103,178	$ 56,581	$ 252,696
Trapped Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total System Balancing Sales	$ 414,411,316	$ 55,707,094	$ 33,731,342	$ 22,908,705	$ 13,856,765	$ 13,033,349	$ 16,033,733	$ 44,411,998	$ 45,919,325	$ 52,123,980	$ 36,061,435	$ 32,943,046	$ 47,680,544
Total Special Sales For Resale	$ 426,328,887	$ 56,390,554	$ 34,696,862	$ 23,940,195	$ 14,586,454	$ 13,630,324	$ 17,006,177	$ 45,349,208	$ 48,953,728	$ 53,008,771	$ 36,890,962	$ 33,560,841	$ 48,314,812

Purchased Power & Net Interchange													
Long Term Firm Purchases													
Appaloosa 1A Solar	$ 8,781,386	$ 476,579	$ 523,356	$ 771,696	$ 833,331	$ 975,792	$ 1,030,696	$ 902,929	$ 879,702	$ 829,738	$ 660,259	$ 490,655	$ 406,654
Appaloosa 1B Solar	$ 5,854,258	$ 317,719	$ 348,904	$ 514,464	$ 555,554	$ 650,528	$ 687,130	$ 601,953	$ 586,468	$ 553,159	$ 440,172	$ 327,103	$ 271,103
Castle Solar UoU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar IHC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind	$ 11,764,725	$ 1,348,848	$ 1,136,654	$ 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	$ 8,939,587	$ 1,025,293	$ 863,560	$ 784,236	$ 772,111	$ 631,271	$ 565,347	$ 564,366	$ 445,199	$ 628,829	$ 828,668	$ 811,823	$ 1,018,881
Cedar Springs Wind IV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combine Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cove Mountain Solar	$ 3,824,831	$ 183,114	$ 199,253	$ 335,342	$ 365,062	$ 420,185	$ 451,894	$ 438,350	$ 414,770	$ 355,679	$ 286,322	$ 205,725	$ 169,135
Cove Mountain Solar II	$ 9,457,003	$ 453,001	$ 492,928	$ 829,598	$ 903,121	$ 1,039,489	$ 1,117,932	$ 1,084,426	$ 1,026,092	$ 879,908	$ 708,326	$ 506,098	$ 416,084
Deseret Purchase	$ 27,684,996	$ 3,228,408	$ 3,092,614	$ 3,010,571	$ 2,973,793	$ 3,009,156	$ 2,719,178	$ 3,228,408	$ 3,228,408	$ 3,194,459	$ -	$ -	$ -
Eagle Mountain - UAMPS/UMPA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 20yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 25yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gemstate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Graphite Solar	$ 6,247,480	$ 311,883	$ 365,922	$ 557,963	$ 612,332	$ 686,777	$ 704,723	$ 687,351	$ 642,989	$ 576,256	$ 480,478	$ 355,140	$ 265,665
Hermiston Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Horseshoe Solar	$ 5,332,320	$ 233,718	$ 300,509	$ 437,779	$ 495,804	$ 591,109	$ 654,482	$ 643,280	$ 609,542	$ 507,018	$ 407,367	$ 251,783	$ 199,930
Hunter Solar	$ 7,031,207	$ 369,331	$ 433,652	$ 637,866	$ 665,722	$ 759,120	$ 785,546	$ 746,797	$ 702,015	$ 654,578	$ 558,601	$ 396,190	$ 321,788
Hurricane Purchase	$ 43,768	$ 43,768	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Buythru	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Reserves	$ 3,264,140	$ 272,680	$ 264,660	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680
Milican Solar	$ 2,898,880	$ 95,313	$ 150,647	$ 222,859	$ 280,511	$ 332,937	$ 362,395	$ 408,109	$ 360,617	$ 290,222	$ 190,032	$ 121,715	$ 83,523
Milford Solar	$ 6,937,492	$ 350,630	$ 418,195	$ 595,592	$ 662,485	$ 778,851	$ 821,177	$ 731,293	$ 704,005	$ 656,707	$ 529,625	$ 385,321	$ 303,612
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	$ 20,600,000	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667
Pavant III Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PGE Cove	$ 140,000	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667	$ 11,667
Prineville Solar	$ 1,931,376	$ 65,430	$ 103,415	$ 148,062	$ 186,364	$ 221,194	$ 240,766	$ 271,137	$ 239,584	$ 192,816	$ 126,252	$ 80,864	$ 55,491
Rocket Solar	$ 5,684,265	$ 257,917	$ 322,155	$ 469,128	$ 531,644	$ 621,291	$ 698,208	$ 715,730	$ 647,631	$ 544,498	$ 414,062	$ 252,964	$ 209,039
Sigurd Solar	$ 5,900,441	$ 308,030	$ 356,200	$ 507,232	$ 553,807	$ 636,517	$ 699,580	$ 650,415	$ 596,230	$ 556,646	$ 451,695	$ 317,435	$ 266,651
Skysol Solar	$ 5,920,135	$ 277,872	$ 373,145	$ 543,974	$ 572,773	$ 517,340	$ 856,561	$ 578,605	$ 797,081	$ 416,253	$ 495,730	$ 251,550	$ 239,252
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 Geotherma	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Buttes Wind	$ 20,858,257	$ 2,812,455	$ 1,934,623	$ 2,152,484	$ 1,628,729	$ 1,438,793	$ 1,215,151	$ 811,932	$ 957,067	$ 1,194,423	$ 1,748,905	$ 2,371,134	$ 2,592,560
Top of the World Wind	$ 38,689,566	$ 3,276,985	$ 3,065,567	$ 3,276,985	$ 3,171,276	$ 3,276,985	$ 3,171,276	$ 3,276,985	$ 3,276,985	$ 3,171,276	$ 3,276,985	$ 3,171,276	$ 3,276,985
Wolverine Creek Wind	$ 10,735,370	$ 793,717	$ 942,652	$ 1,181,937	$ 1,087,538	$ 821,216	$ 882,210	$ 698,831	$ 664,714	$ 785,048	$ 864,179	$ 1,004,655	$ 1,008,672
Glen Canyon	$ 337,293	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,616	$ 325,678
Rush Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Cente	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anticline Wind	$ 18,647	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,647
Boswell Springs Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Two River Wind LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Creek	$ 9,824,810	$ -	$ -	$ -	$ -	$ -	$ 19,719	$ 1,377,208	$ 1,089,634	$ 1,309,941	$ 2,181,521	$ 2,132,507	$ 1,714,280
UT Schedule Adjustment	$ (33,209,363)	$ (1,465,261)	$ (1,769,465)	$ (2,995,070)	$ (3,347,722)	$ (3,979,428)	$ (4,027,451)	$ (3,768,575)	$ (3,517,076)	$ (3,033,387)	$ (2,526,832)	$ (1,597,900)	$ (1,181,194)
Long Term Firm Purchases Total	$ 202,636,958	$ 17,361,088	$ 16,242,842	$ 17,611,277	$ 17,116,603	$ 16,856,346	$ 16,996,767	$ 17,988,702	$ 17,534,013	$ 17,687,882	$ 15,809,202	$ 15,512,370	$ 15,919,867

Qualifying Facilities													
QF California	$ 1,689,996	$ 143,982	$ 143,943	$ 156,491	$ 157,787	$ 137,793	$ 134,130	$ 135,443	$ 134,275	$ 129,451	$ 135,642	$ 142,120	$ 138,938
QF Idaho	$ 7,320,703	$ 599,189	$ 537,640	$ 620,168	$ 660,495	$ 750,735	$ 742,113	$ 653,772	$ 551,745	$ 515,445	$ 577,897	$ 553,586	$ 557,917
QF Oregon	$ 42,905,895	$ 2,075,059	$ 2,552,944	$ 3,496,862	$ 4,439,794	$ 4,752,983	$ 4,922,770	$ 5,207,762	$ 4,661,076	$ 3,856,461	$ 2,976,207	$ 2,152,393	$ 1,811,583
QF Utah	$ 6,089,824	$ 359,735	$ 403,634	$ 480,489	$ 577,321	$ 633,622	$ 651,572	$ 593,822	$ 598,387	$ 589,266	$ 510,761	$ 383,471	$ 307,744
QF Washington	$ 231,326	$ -	$ -	$ -	$ 22,558	$ 23,309	$ 44,797	$ 46,291	$ 46,291	$ 44,797	$ 3,283	$ -	$ -
QF Wyoming	$ 206,138	$ 25,105	$ 19,178	$ 24,010	$ 20,453	$ 18,880	$ 7,576	$ 11,504	$ 12,860	$ 17,487	$ 16,668	$ 18,737	$ 13,680
Biomass One QF	$ 18,597,518	$ 1,467,149	$ 1,682,299	$ 1,801,148	$ 1,760,367	$ 1,478,176	$ 1,902,739	$ 1,373,031	$ 1,795,085	$ 1,379,180	$ 1,774,602	$ 1,408,658	$ 775,084
Chopin Wind QF	$ 2,052,812	$ 193,044	$ 216,789	$ 168,226	$ 188,753	$ 161,939	$ 177,933	$ 160,795	$ 152,387	$ 133,330	$ 156,651	$ 177,435	$ 165,528
DCFP QF	$ 147,652	$ 5,078	$ 1,899	$ 1,965	$ 2,612	$ 5,237	$ 8,926	$ 19,768	$ 53,161	$ 20,220	$ 14,726	$ 8,333	$ 5,725
Enterprise Solar I QF	$ 12,428,315	$ 605,776	$ 772,740	$ 956,940	$ 1,100,161	$ 1,246,936	$ 1,367,030	$ 1,552,309	$ 1,503,979	$ 1,161,053	$ 940,221	$ 689,473	$ 531,699
Escalante Solar I QF	$ 11,464,945	$ 555,383	$ 702,390	$ 861,800	$ 1,001,202	$ 1,180,119	$ 1,278,616	$ 1,437,770	$ 1,392,853	$ 1,073,040	$ 857,708	$ 627,972	$ 496,091
Escalante Solar II QF	$ 10,801,514	$ 522,020	$ 659,365	$ 811,762	$ 941,605	$ 1,115,246	$ 1,221,823	$ 1,358,137	$ 1,305,905	$ 1,011,320	$ 804,026	$ 587,622	$ 462,683
Escalante Solar III QF	$ 9,936,063	$ 507,994	$ 644,271	$ 787,602	$ 915,846	$ 1,085,562	$ 731,324	$ 1,315,175	$ 1,267,280	$ 982,800	$ 735,783	$ 538,302	$ 424,125
ExxonMobil QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Five Pine Wind QF	$ 9,710,176	$ 563,431	$ 1,038,012	$ 944,560	$ 1,014,433	$ 442,482	$ 736,691	$ 615,701	$ 733,643	$ 820,900	$ 889,560	$ 933,939	$ 976,823
Granite Mountain East Solar QF	$ 10,778,945	$ 538,975	$ 634,052	$ 873,532	$ 974,584	$ 1,145,735	$ 1,244,331	$ 1,333,659	$ 1,255,131	$ 959,245	$ 795,497	$ 568,358	$ 455,845
Granite Mountain West Solar QF	$ 7,121,644	$ 356,801	$ 420,253	$ 579,379	$ 646,457	$ 758,828	$ 823,479	$ 883,781	$ 831,879	$ 634,512	$ 509,122	$ 375,534	$ 301,619
Iron Springs Solar QF	$ 11,073,378	$ 623,133	$ 681,626	$ 875,888	$ 1,002,096	$ 1,119,438	$ 1,269,977	$ 1,344,268	$ 1,314,577	$ 987,521	$ 802,236	$ 566,110	$ 486,508
Latigo Wind Park QF	$ 9,793,430	$ 1,008,523	$ 974,723	$ 1,127,257	$ 888,162	$ 870,272	$ 743,515	$ 687,491	$ 567,983	$ 624,430	$ 806,218	$ 703,907	$ 790,950
Mountain Wind 1 QF	$ 9,042,366	$ 1,421,577	$ 1,090,928	$ 884,151	$ 699,375	$ 494,107	$ 509,817	$ 413,520	$ 443,831	$ 466,242	$ 672,794	$ 930,752	$ 1,015,271
Mountain Wind 2 QF	$ 14,002,090	$ 2,060,743	$ 1,624,957	$ 1,360,834	$ 1,082,104	$ 769,391	$ 912,714	$ 759,165	$ 732,764	$ 769,110	$ 1,005,488	$ 1,432,507	$ 1,492,316
North Point Wind QF	$ 20,647,148	$ 1,124,011	$ 2,125,702	$ 1,999,790	$ 2,164,701	$ 938,564	$ 1,585,605	$ 1,359,834	$ 1,726,325	$ 1,853,270	$ 1,964,389	$ 1,885,477	$ 1,919,480
Oregon Wind Farm QF	$ 14,121,537	$ 1,003,550	$ 1,532,569	$ 1,246,680	$ 1,005,615	$ 725,755	$ 954,399	$ 1,241,939	$ 2,818,117	$ 871,584	$ 870,570	$ 715,262	$ 1,135,497
Orchard Wind 1 QF	$ 1,137,294	$ 63,171	$ 69,701	$ 97,721	$ 124,816	$ 110,803	$ 123,524	$ 123,449	$ 105,362	$ 79,489	$ 84,148	$ 75,107	$ 80,003
Orchard Wind 2 QF	$ 1,137,294	$ 61,356	$ 68,707	$ 91,023	$ 124,993	$ 112,506	$ 123,255	$ 125,420	$ 106,117	$ 79,928	$ 85,657	$ 76,765	$ 81,568
Orchard Wind 3 QF	$ 1,137,294	$ 63,522	$ 66,945	$ 105,763	$ 122,943	$ 112,010	$ 124,350	$ 121,662	$ 105,662	$ 78,908	$ 84,637	$ 72,465	$ 78,427
Orchard Wind 4 QF	$ 1,137,294	$ 63,331	$ 69,219	$ 103,949	$ 122,994	$ 111,676	$ 123,692	$ 122,969	$ 105,683	$ 78,915	$ 82,859	$ 73,472	$ 78,535
Pavant II Solar QF	$ 5,116,247	$ 208,969	$ 282,470	$ 407,283	$ 478,347	$ 499,355	$ 597,409	$ 546,878	$ 758,285	$ 464,865	$ 411,225	$ 254,555	$ 206,606
Pioneer Wind Park I QF	$ 10,709,139	$ 1,308,719	$ 979,538	$ 1,188,677	$ 905,868	$ 709,742	$ 649,747	$ 657,551	$ 685,231	$ 449,790	$ 819,706	$ 1,261,619	$ 1,092,950
Power County North Wind QF	$ 6,161,396	$ 445,195	$ 643,434	$ 644,236	$ 645,185	$ 315,946	$ 462,404	$ 349,087	$ 435,452	$ 404,038	$ 598,734	$ 548,859	$ 668,826
Power County South Wind QF	$ 5,500,991	$ 394,670	$ 567,630	$ 581,722	$ 598,265	$ 271,124	$ 409,979	$ 308,756	$ 406,414	$ 359,373	$ 525,200	$ 496,807	$ 581,053
Roseburg Dillard QF	$ 1,605,357	$ 64,337	$ 238,412	$ 149,346	$ 176,614	$ 110,536	$ 109,492	$ 182,380	$ 248,535	$ 60,050	$ 116,684	$ 74,410	$ 74,560
Sage I Solar QF	$ 2,224,606	$ 79,115	$ 80,953	$ 185,750	$ 201,479	$ 230,722	$ 255,841	$ 330,468	$ 328,474	$ 202,900	$ 152,736	$ 102,564	$ 73,604
Sage II Solar QF	$ 2,226,990	$ 79,198	$ 81,049	$ 185,945	$ 201,695	$ 230,934	$ 256,127	$ 330,821	$ 328,839	$ 203,129	$ 152,889	$ 102,691	$ 73,674
Sage III Solar QF	$ 1,832,725	$ 66,690	$ 67,449	$ 153,415	$ 164,218	$ 189,113	$ 209,266	$ 269,677	$ 267,843	$ 167,470	$ 128,126	$ 86,929	$ 62,528
Spanish Fork Wind 2 QF	$ 2,929,265	$ 196,128	$ 217,811	$ 233,814	$ 182,707	$ 141,420	$ 288,685	$ 247,949	$ 427,513	$ 236,345	$ 290,348	$ 233,897	$ 232,649
Sunnyside QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sweetwater Solar QF	$ 7,625,670	$ 253,990	$ 379,040	$ 551,639	$ 673,027	$ 797,595	$ 957,706	$ 1,095,186	$ 1,019,583	$ 792,992	$ 615,295	$ 292,965	$ 196,650
Tesoro QF	$ 420,138	$ 33,480	$ 70,038	$ 56,601	$ 34,143	$ 10,708	$ 9,267	$ 8,273	$ 59,913	$ 9,285	$ 11,582	$ 24,123	$ 92,725
Three Peaks Solar QF	$ 8,474,921	$ 409,850	$ 492,863	$ 614,683	$ 835,185	$ 866,466	$ 913,479	$ 1,061,665	$ 1,017,830	$ 791,169	$ 669,197	$ 437,902	$ 364,633
Threemile Canyon Wind QF	$ 1,802,363	$ 82,972	$ 180,579	$ 139,659	$ 183,820	$ 181,293	$ 218,186	$ 208,329	$ 181,311	$ 120,822	$ 125,922	$ 99,256	$ 80,214
Utah Pavant Solar QF	$ 6,844,979	$ 259,763	$ 352,596	$ 546,244	$ 642,550	$ 673,453	$ 865,705	$ 762,807	$ 956,395	$ 617,319	$ 578,864	$ 318,588	$ 270,697
Utah Red Hills Solar QF	$ 11,458,023	$ 480,440	$ 640,061	$ 773,732	$ 1,020,201	$ 1,193,809	$ 1,227,730	$ 1,524,395	$ 1,463,201	$ 1,300,074	$ 800,670	$ 579,337	$ 454,373
Qualifying Facilities Total	$ 309,645,401	$ 20,375,152	$ 24,008,407	$ 26,870,737	$ 28,705,529	$ 26,724,323	$ 29,897,721	$ 30,882,659	$ 32,907,174	$ 25,397,527	$ 24,154,528	$ 20,612,262	$ 19,109,381
Mid-Columbia Contracts													
Douglas - Wells	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grant Reasonable	$ (9,177,438)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)
Grant Meaningful Priority	$ 63,502,271	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856	$ 5,291,856
Grant Surplus	$ 2,448,617	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051	$ 204,051
Mid-Columbia Contracts Total	$ 56,773,451	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121	$ 4,731,121
Total Long Term Firm Purchases	$ 569,055,810	$ 42,467,361	$ 44,982,370	$ 49,213,135	$ 50,553,253	$ 48,311,790	$ 51,625,609	$ 53,602,482	$ 55,172,308	$ 47,816,530	$ 44,694,851	$ 40,855,752	$ 39,760,370

Storage & Exchange													
Rush lake_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Umpqua Storage Placeholder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cowlitz Swift	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EWEB FC I	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCo Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCO FC III	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SCL State Line	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage & Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Short Term Firm Purchases													
COB	$ 20,243,300	$ 2,925,000	$ 2,812,500	$ 2,925,000	$ -	$ -	$ -	$ 3,910,400	$ 4,060,800	$ 3,609,600	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ 5,719,560	$ 1,931,280	$ 1,857,000	$ 1,931,280	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Purchases	$ 25,962,860	$ 4,856,280	$ 4,669,500	$ 4,856,280	$ -	$ -	$ -	$ 3,910,400	$ 4,060,800	$ 3,609,600	$ -	$ -	$ -
System Balancing Purchases													
COB	$ 63,650,089	$ 3,577,370	$ 8,917,148	$ 8,552,901	$ 2,229,624	$ 568,896	$ 3,419,430	$ 14,664,021	$ 10,227,506	$ 4,586,615	$ 1,607,422	$ 1,712,135	$ 3,587,020
Four Corners	$ 57,150,782	$ 5,038,616	$ 3,026,652	$ 3,352,904	$ 3,724,323	$ 2,731,166	$ 4,102,289	$ 11,406,552	$ 5,933,034	$ 7,352,791	$ 3,328,465	$ 2,788,268	$ 4,365,722
Mead	$ 2,569,643	$ 82,684	$ -	$ 2	$ 119,953	$ -	$ 390,192	$ -	$ 1,449,544	$ 366,565	$ -	$ -	$ 160,704
Mid Columbia	$ 708,245,970	$ 70,645,648	$ 55,765,266	$ 46,933,777	$ 40,790,339	$ 42,892,477	$ 43,556,401	$ 102,397,826	$ 98,194,090	$ 64,700,612	$ 38,087,988	$ 39,300,218	$ 64,981,329
Mona	$ 15,719,250	$ 1,312,218	$ 1,085,540	$ 342,409	$ 552,746	$ 248,182	$ 780,738	$ 343,249	$ 93,292	$ 4,461,958	$ 2,447,932	$ 2,169,734	$ 1,881,252
NOB	$ 147,513,317	$ 14,086,456	$ 13,678,938	$ 11,240,988	$ 4,563,410	$ 8,143,196	$ 8,225,246	$ 19,859,510	$ 18,188,165	$ 16,361,491	$ 8,159,968	$ 11,867,494	$ 13,138,455
Palo Verde	$ 22,139,003	$ 2,630,475	$ 1,278,512	$ 1,691,866	$ 818,098	$ 1,319,328	$ 1,800,881	$ 3,166,300	$ 3,535,829	$ 112,763	$ 1,934,898	$ 1,744,420	$ 2,105,633
EIM Imports/Exports	$ (132,040,852)	$ (14,965,950)	$ (11,323,929)	$ (9,984,684)	$ (7,446,441)	$ (7,771,253)	$ (8,104,493)	$ (14,645,162)	$ (15,240,008)	$ (12,752,502)	$ (8,710,848)	$ (9,237,720)	$ (11,857,863)
Emergency Purchases	$ 13,967,736	$ -	$ -	$ -	$ 4,026,201	$ 2,296,161	$ 6,012,075	$ 1,288,485	$ 305,852	$ 8,473	$ 30,489	$ -	$ -
Total System Balancing Purchases	$ 898,914,937	$ 82,407,518	$ 72,428,127	$ 62,130,162	$ 49,378,254	$ 50,428,153	$ 60,182,758	$ 138,480,781	$ 122,687,304	$ 85,198,766	$ 46,886,315	$ 50,344,549	$ 78,362,251
Total Purchased Power & Net Interchange	$ 1,493,933,607	$ 129,731,159	$ 122,079,997	$ 116,199,577	$ 99,931,507	$ 98,739,943	$ 111,808,367	$ 195,993,663	$ 181,920,412	$ 136,624,896	$ 91,581,165	$ 91,200,301	$ 118,122,621
Wheeling & U. of F. Expense													
Firm Wheeling	$ 163,405,118	$ 12,492,560	$ 13,134,268	$ 13,941,364	$ 14,029,707	$ 13,304,354	$ 13,897,944	$ 15,914,957	$ 15,199,584	$ 14,574,309	$ 12,615,608	$ 11,670,083	$ 12,630,380
C&T EIM Admin fee	$ 2,734,506	$ 210,477	$ 192,813	$ 230,652	$ 220,405	$ 231,652	$ 233,135	$ 235,464	$ 256,292	$ 228,219	$ 226,374	$ 224,006	$ 245,016
ST Firm & Non-Firm	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Wheeling & U. of F. Expense	$ 166,139,624	$ 12,703,037	$ 13,327,082	$ 14,172,016	$ 14,250,112	$ 13,536,005	$ 14,131,079	$ 16,150,420	$ 15,455,876	$ 14,802,529	$ 12,841,982	$ 11,894,090	$ 12,875,396
Coal Fuel Burn Expense													
Colstrip	$ 19,942,369	$ 1,347,207	$ 1,720,509	$ 1,775,532	$ 1,541,829	$ 1,267,360	$ 986,761	$ 1,958,500	$ 1,936,029	$ 1,995,318	$ 1,906,745	$ 1,939,939	$ 1,566,641
Craig	$ 19,546,377	$ 1,963,381	$ 1,480,932	$ 1,514,896	$ 988,914	$ 1,232,927	$ 1,440,005	$ 1,926,717	$ 2,044,054	$ 1,621,474	$ 1,700,734	$ 1,707,230	$ 1,925,114
Dave Johnston	$ 45,234,123	$ 4,464,757	$ 4,355,264	$ 5,005,749	$ 4,046,745	$ 1,893,284	$ 2,734,596	$ 3,219,902	$ 3,455,797	$ 2,551,557	$ 4,355,857	$ 4,171,324	$ 4,979,293
Hayden	$ 11,875,630	$ 1,013,218	$ 1,007,905	$ 851,433	$ 662,831	$ 950,011	$ 950,431	$ 1,038,877	$ 1,049,750	$ 950,327	$ 1,198,007	$ 1,152,745	$ 1,050,094
Hunter	$ 167,870,240	$ 16,022,092	$ 12,824,884	$ 8,287,338	$ 7,676,028	$ 12,266,290	$ 13,677,299	$ 24,953,435	$ 23,725,041	$ 18,034,318	$ 8,594,091	$ 8,449,168	$ 13,360,256
Huntington	$ 76,807,787	$ 7,442,481	$ 6,044,206	$ 4,868,430	$ 3,615,108	$ 4,451,337	$ 5,825,312	$ 11,653,134	$ 11,286,607	$ 7,975,739	$ 3,867,022	$ 3,686,324	$ 6,092,087
Jim Bridger	$ 157,086,494	$ 14,708,800	$ 13,428,289	$ 13,285,622	$ 13,028,232	$ 11,162,372	$ 13,513,866	$ 13,896,200	$ 12,964,240	$ 11,310,484	$ 13,565,264	$ 13,013,873	$ 13,209,252
Naughton	$ 31,553,788	$ 4,191,003	$ 3,097,930	$ 2,701,049	$ 2,887,089	$ 2,049,051	$ 1,841,459	$ 2,738,509	$ 3,220,445	$ 2,310,202	$ 2,077,732	$ 2,241,579	$ 2,197,739
Wyodak	$ 17,471,353	$ 2,152,929	$ 1,883,038	$ 1,498,364	$ 1,988,513	$ 511,479	$ 966,576	$ 1,216,056	$ 1,288,498	$ 853,683	$ 1,426,799	$ 1,544,897	$ 2,140,520
Total Coal Fuel Burn Expense	$ 547,388,163	$ 53,305,868	$ 45,842,956	$ 39,788,413	$ 36,435,289	$ 35,784,111	$ 41,936,304	$ 62,601,330	$ 60,970,462	$ 47,603,103	$ 38,692,250	$ 37,907,079	$ 46,520,997
Gas Fuel Burn Expense													
Chehalis	$ 194,110,343	$ 26,735,556	$ 20,849,638	$ 16,691,508	$ 10,634,181	$ 14,030,812	$ 12,964,719	$ 15,006,098	$ 14,938,338	$ 12,795,128	$ 12,575,672	$ 17,158,652	$ 19,730,040
Currant Creek	$ 116,612,906	$ 18,272,562	$ 14,951,100	$ 10,470,425	$ 7,265,618	$ 5,605,940	$ 3,693,810	$ 9,134,717	$ 8,592,447	$ 8,535,212	$ 8,440,334	$ 9,000,907	$ 12,649,834
Gadsby	$ 33,029,691	$ 4,646,070	$ 4,406,756	$ 3,840,494	$ 2,602,572	$ 859,282	$ 818,785	$ 2,857,755	$ 2,639,873	$ 1,080,118	$ 2,553,064	$ 3,033,448	$ 3,691,474
Gadsby CT	$ 7,592,963	$ 1,312,879	$ 1,269,180	$ 1,146,022	$ 1,087,915	$ -	$ -	$ 922,320	$ 189,155	$ -	$ 318,961	$ 439,466	$ 907,066
Hermiston	$ 47,324,426	$ 6,626,650	$ 5,733,652	$ 2,777,825	$ 2,102,643	$ 3,192,642	$ 2,258,359	$ 2,680,935	$ 4,155,361	$ 3,999,575	$ 4,167,945	$ 5,048,615	$ 4,580,224
Jim Bridger - Gas	$ 123,772,793	$ -	$ -	$ -	$ -	$ 11,265,229	$ 11,749,182	$ 16,054,356	$ 16,000,188	$ 12,097,497	$ 15,967,358	$ 18,097,376	$ 22,541,607
Lake Side 1	$ 121,045,775	$ 17,168,922	$ 15,356,186	$ 9,742,872	$ 6,409,977	$ 6,325,007	$ 5,130,088	$ 9,159,716	$ 9,167,309	$ 8,870,079	$ 8,099,194	$ 11,280,885	$ 14,335,539
Lake Side 2	$ 127,129,351	$ 19,829,823	$ 16,279,320	$ 12,580,399	$ 2,684,077	$ 248,312	$ 7,810,002	$ 10,507,530	$ 10,610,226	$ 9,735,085	$ 9,717,558	$ 12,161,757	$ 14,965,261
Naughton - Gas	$ 66,229,395	$ 7,434,787	$ 5,450,994	$ 6,525,861	$ 1,800,416	$ 5,983,443	$ 6,586,705	$ 4,781,948	$ 5,724,815	$ 5,021,951	$ 2,887,011	$ 7,429,851	$ 6,601,613
Total Gas Fuel Burn	$ 836,847,643	$ 102,027,249	$ 84,296,826	$ 63,775,406	$ 34,587,400	$ 47,510,667	$ 51,011,650	$ 71,105,376	$ 72,017,713	$ 62,134,645	$ 64,727,097	$ 83,650,957	$ 100,002,659
Gas Physical	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas Swaps	$ (19,945,513)	$ (10,260,271)	$ (8,075,297)	$ (510,368)	$ 778,905	$ 1,007,515	$ 788,955	$ (1,206,784)	$ (1,390,280)	$ (810,105)	$ 1,736,899	$ 630,930	$ (2,635,612)
Clay Basin Gas Storage	$ (1,988,037)	$ (733,232)	$ (647,448)	$ (211,830)	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ (262,779)	$ (498,446)
Pipeline Reservation Fees	$ 41,990,122	$ 3,531,271	$ 3,464,667	$ 3,527,991	$ 3,492,943	$ 3,437,503	$ 3,410,229	$ 3,527,647	$ 3,552,019	$ 3,415,005	$ 3,565,480	$ 3,508,093	$ 3,557,275
Total Gas Fuel Burn Expense	$ 856,904,215	$ 94,565,016	$ 79,038,748	$ 66,581,198	$ 38,911,491	$ 52,007,927	$ 55,263,077	$ 73,478,481	$ 74,231,694	$ 64,791,788	$ 70,081,718	$ 87,527,201	$ 100,425,875

Other Generation													
Blundell	$ 4,440,902	$ 443,392	$ 228,935	$ 88,076	$ 360,802	$ 379,715	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Blundell Bottoming Cycle	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dunlap I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ekola Flats Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek III Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek IV 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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock River 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Integration Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Generation	$ 4,440,902	$ 443,392	$ 228,935	$ 88,076	$ 360,802	$ 379,715	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Net Power Cost	**$ 2,642,477,625**	**$ 234,357,918**	**$ 225,820,856**	**$ 212,889,084**	**$ 175,302,747**	**$ 186,817,377**	**$ 206,523,948**	**$ 303,292,748**	**$ 284,055,026**	**$ 211,227,288**	**$ 176,707,480**	**$ 195,399,802**	**$ 230,083,350**

REDACTED
Docket No. UE 420
Exhibit PAC/103
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Update to Renewable Energy Production Tax Credits

April 2023

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

Docket No. UE 420
Exhibit PAC/104
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Costs Step Log

April 2023

2024 TAM Step Log

ORTAM23			$ 1,977,454,591
	Description	**Detail**	**Impact**
	Routine Updates		$ 98,994,040
Step 1	Trapped Energy	Removing the trapped energy modeling construct in favor of wind curtailment to reflect the realities of system operations.	$ 14,354,348
Step 2	Ozone Transport Rule	Impact of the EPA's Ozone Transport Rule on NPC.	$ 202,475,788
Step 3	Jim Bridger Outage	Assesses the impact of JB Gas units 1 & 2 going on outage to convert to gas.	$ 41,973,900
Step 4	Jim Bridger Gas Conversion	Impact of converting Jim Bridger Coal to Jim Bridger Gas (units 1 and 2).	$ 92,194,553
Step 5	WA Cap and Invest	Impact of the WA Cap and Invest program on NPC.	$ 72,970,628
Step 6	Klamath Deconstruction	Impact of the deconstruction of the hydroelectric projects on the Klamath river (dam removal).	$ 53,467,853
Step 7	Gateway South	Gateway South transmission project in-service by October 2024	$ (19,031,995)
Step 8	Coal Supply Limitations	Impact of the reduced availability of coal for all Company coal-fired plants in Utah	$ 107,623,919
ORTAM24			$ 2,642,477,625

Docket No. UE 420
Exhibit PAC/105
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

February 28, 2023 Notice Letter

April 2023

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

February 28, 2023

VIA ELECTRONIC MAIL

Attn: Parties to docket UE 400

RE: 2024 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 2024 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 Aurora model or to the logic of the Aurora model by March 1st of the year of a stand-alone TAM filing."[1] Consistent with the TAM Guidelines, PacifiCorp will be filing the TAM on April 3, 2023. As a result, the company is providing this notice to comply with the pre-filing review requirement and the methodology change notice requirement on February 28, 2022.

PacifiCorp provides notice of the following planned changes to the 2024 TAM:[2]

- The trapped energy zone modeling construct will be removed to more accurately reflect how the Company's system is operated.

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

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

cc: UE 400 Service List

[1] *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).
[2] PacifiCorp is incorporating the changes supported in testimony in the 2023 TAM (UE 400), and described as non-precedential in the settlement to that proceeding. *See* Order No. 22-389, Appendix A at ¶27. Since these changes were described in-depth in that proceeding, they are not included in this letter.

REDACTED
Docket No. UE 420
Exhibit PAC/106
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

2019 Benchmark Report

April 2023

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 1, 2023

Re: UE 400—Benchmarking Study

In Order No. 22-389, the Commission adopted an all-party stipulation which commits the Company to "make best efforts to provide to parties a benchmarking study that uses inputs from 2019 actuals on February 1, 2023"[1]

Results of the Benchmarking Study

The results of the benchmarking study show that Aurora simulated 2019 historical net power costs (NPC) at $74 million less than actual NPC. Aurora estimated total company 2019 NPC to be $1,586 million compared to actual 2019 costs of $1,660 million, a variance of 4.5 percent.

Confidential Table 1 illustrates a detailed comparison between the benchmarking study and 2019 Actual NPC. Long-term firm sales and long-term firm purchase dollars and megawatt-hours (MWh) are based on actual transactions. Hydroelectric generation, wind generation and solar generation are based on actual generation. The variance between short-term firm and system balancing sales and purchases is driven by the fact that Aurora balances the system differently than the Company does in actual operations. More specifically, Aurora faces a different set of operational constraints compared to what the Company faces in real time. For example, market liquidity in the benchmarking study is predetermined based on market capacity limits that allow more sales transactions than the Company's historical experience.

It is important to note that the NPC forecast is designed with hourly average inputs. Given a certain set of hourly average input variables, Aurora applies its system balancing logic to meet load and wholesale obligations under the operational constraints assumed in the model. In actual operations, the Company faces a different set of real (moment-to-moment) system constraints, many of which are not able to be fully reflected in Aurora's modeling assumptions. Furthermore, Aurora is not able to forecast thermal dispatch in the same way that PacifiCorp dispatches its thermal plants in real time and Aurora's optimization of the system is perfect which means that after the optimization is complete no net savings can be further achieved by backing down one unit and ramping up another unit.

In actual operations, as a matter of prudence, PacifiCorp seeks to optimize the system. However, in reality, PacifiCorp faces a different set of constraints resulting from actual market conditions, and in real time, system dispatch will choose to balance the system using coal plants, gas plants and system balancing purchases and sales in an order that is feasible to current market conditions. The order of selection of coal plants, gas plants and system balancing purchase and sales results in differences in each resource category compared to the benchmarking study results. Consequently, and as shown in Confidential Table 1 below, the coal and natural gas

[1] In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism, Docket No. UE-400, Order No. 22-389, Appendix A at 6 (October 25, 2022).

dispatch (on a MWh basis) in Aurora was eight percent more and 26 percent more than actuals, respectively.

Confidential Table 1 – Net Power Cost Differential Summary – Benchmark
[CONFIDENTIAL BEGINS]

[redacted]

[CONFIDENTIAL ENDS]

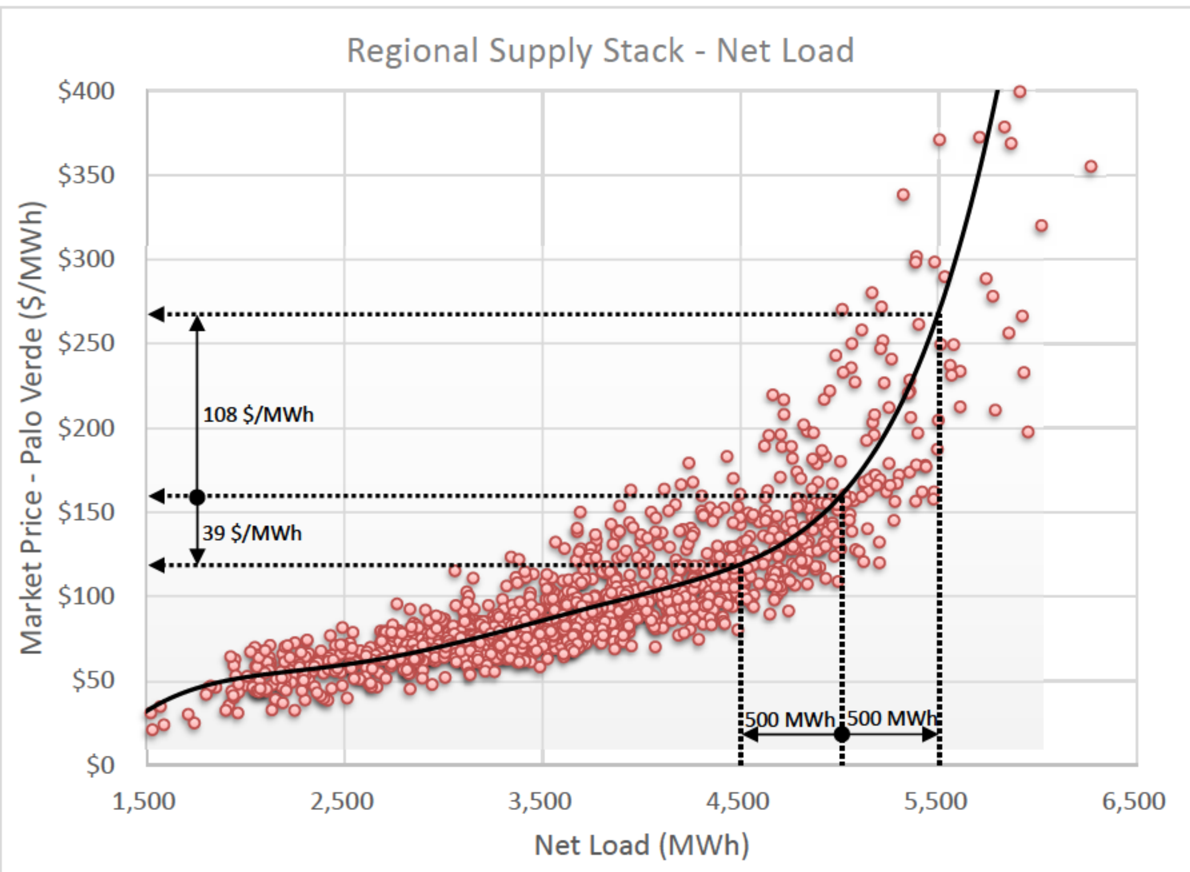
Conclusions

When actual data is used as inputs, Aurora produces 2019 NPC below the actual 2019 NPC and this is to be expected.

First, Aurora applies its system balancing logic with perfect foresight and perfect execution. That is to say, Aurora knows the future and operates the system with perfect efficiency in every hour. In reality, the future is uncertain, humans cannot know exactly at what level variable resources will be producing in a future hour and there will always be some inefficiency within a grouping of individuals (people). In the context of NPC, this reality of the human experience deviates from the perfection inherent in Aurora and the associated perfectly-low Aurora NPC.

Second, there is an asymmetry in the response of market prices to changes in load and generation. As an illustrative example, Figure 1 shows a proxy supply/demand curve (with inelastic demand) based on actual load, wind, and solar data within the region. It is observed that because of the asymmetry of market price response, a 500 MWh increase in net load (load less wind less solar) results in a $108 dollar per MWh ($/MWh) increase in market price, whereas an identical 500 MWh decrease in net load results in only a $39/MWh decrease to market price.

Figure 1



This asymmetrical response impacts actual operations because the net load forecasts, in reality, are uncertain (i.e., there is no perfect foresight). This uncertainty results in an equal chance of net load being higher or lower than forecasted. However, the impact to NPC is an asymmetric response wherein the actual NPC has a greater chance of being higher than the forecast NPC and consequently the forecast NPC is biased downwards relative to the actual NPC. This is the result observed in this benchmarking study.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

REDACTED
Docket No. UE 420
Exhibit PAC/200
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of James Owen

April 2023

TABLE OF CONTENTS

ATTACHED EXHIBITS

Highly Confidential Exhibit PAC/201—Hunter/Gentry CSA Analysis

Highly Confidential Exhibit PAC/202—Dave Johnston CSA Analysis

Highly Confidential Exhibit PAC/203—Wyodak CSA Analysis

Highly Confidential Exhibit PAC/204—Hunter/Bronco CSA Analysis

Confidential Exhibit PAC/205—CSA Contract Minimums Table

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 James Owen. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Environmental, Fuels, and Mining.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Mining Engineering, a Master of Business Administration Degree, and a Juris Doctor Degree, all from the University of Utah. I joined the Utah Department of Natural Resources – Division of Oil Gas and Mining in November 2008, and held positions of increasing responsibility within the agency, including responsibilities for environmental permitting, enforcement of environmental compliance, engineering design, oversight of mine reclamation bonding, environmental program management, and legislative and policy management. I joined PacifiCorp as Director of Environmental in February 2018. I have assumed positions of increasing responsibility since that time and currently serve as Vice President of Environmental, Fuels, and Mining. My current responsibilities encompass strategic planning, stakeholder engagement, regulatory support, support of major generation resource additions, direct oversight of fueling strategy, management of mining operations, and direct oversight of major environmental compliance projects.

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 California, Idaho, Utah, 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 2024 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony:

- Provides a brief update of recent changes in the coal market and how those changes impact the 2024 TAM fuel costs;
- Details new coal supply agreements (CSA) that PacifiCorp entered into since the 2023 TAM, and provides highly confidential exhibits detailing the new CSAs and the analysis that was undertaken to support the prudence of these agreements;
- Provides an update on the Company's evaluation of the termination provisions for the Huntington CSA, and explains the primary reasons behind the reduction to the total-company coal costs—close to $92 million—reflected in the 2024 TAM;[1] and
- Provides updated coal pricing and background on third-party coal contracts and affiliate-owned mines.

[1] Unless otherwise stated, all figures in my testimony are stated on a total-company basis.

III. CHANGES IN COAL MARKET CONDITIONS

Q. What significant changes have occurred in the coal market since 2021?

A. Beginning in the third quarter of 2021, market coal prices throughout the United States began to increase significantly. This was caused by multiple factors, including but not limited to: increased coal demand due to high domestic natural gas prices; low inventories at coal mines and coal-fired power plants; increased demand abroad for coal exports; international and domestic supply chain constraints; labor and material shortages; and general market inflation. The coal market has experienced unprecedented prices and significant fluctuation since 2021.

Q. How do increases to coal prices in the market impact PacifiCorp?

A. Higher prices in the coal market result in higher costs per ton for coal purchased by PacifiCorp when negotiating new or amended coal supply agreements. Fixed pricing and reasonable term provisions in PacifiCorp's coal supply agreements have insulated the Company from significant exposure to market fluctuations. However, market exposure returns when the Company is negotiating new or amended contracts, or in cases where a coal supplier does not meet its coal delivery obligations and the Company is forced to seek sources for replacement coal supply in the market.

Q. How have increased foreign and domestic coal prices impacted PacifiCorp's coal suppliers?

A. Higher market prices result in coal suppliers receiving a higher price per ton for coal sold by the supplier. Coal suppliers have also been impacted by international and domestic supply chain constraints; labor and material shortages; and general market inflation. The Company has observed that coal suppliers are at an increasing risk of becoming insolvent and failing to deliver coal, particularly in cases where their operating costs are increasing due to inflation and other pressures, but the coal supplier is subject to fixed pricing under a coal supply agreement.

Q. Are there additional factors that have impacted coal markets and coal availability for PacifiCorp since 2021?

A. Yes. The Utah coal market was significantly disrupted and depleted due to a mine fire that ignited at American Consolidated Natural Resources' (ACNR) Lila Canyon mine in September 2022. As a result of the fire, the Lila Canyon mine ceased operations and has not resumed coal production as of the date of this filing. PacifiCorp was informed in February 2023 that the extent of the damage from the mine fire is significant. The Lila Canyon mine accounted for more than 25 percent of Utah's total coal production in recent years and was expected to supply [redacted] In 2022, Utah coal mines produced 10.7 million tons while PacifiCorp's Utah plants consumed 5.8 million tons. PacifiCorp's Utah plants have generally consumed more than 50 percent of the coal produced in the state. The significant production shortfall due to the Lila Canyon mine fire negatively affected all large coal consumers including PacifiCorp. Unfortunately, this negative impact is expected to continue into the foreseeable future. In addition to the mine fire, coal suppliers have experienced issues relating to unfavorable geologic and mining conditions, delays and pressure relating to securing federal mining leases, limited availability of trucking and railway transportation for coal, long lead-times for procurement of necessary mining equipment, and limitations in availability of financing.

Q. Have the coal market issues you described resulted in force majeure claims by coal suppliers and declined coal deliveries?

A. Yes. Two of PacifiCorp's largest coal suppliers in Utah made force majeure claims in 2022 that resulted in significant delivery shortfalls of PacifiCorp's contracted coal supply. These coal supply shortfalls have raised reliability concerns and have forced PacifiCorp to utilize other system resources and market purchases to ensure ongoing system reliability. The impact of reduced available coal supplies and higher coal pricing discussed above informed both coal volumes and pricing assumptions in the 2024 TAM.

Q. Has PacifiCorp attempted to procure alternative coal supply to offset the impacts of the supply shortfalls in Utah?

A. Yes. PacifiCorp initiated a Request for Proposals (RFP) in August 2022 to identify all potential alternative coal supply sources. The RFP process resulted in two coal suppliers being selected. One new contract was executed in early 2023, and negotiations are taking place with the second supplier. PacifiCorp has also continued working with coal suppliers that have made force majeure claims and has pursued strategies to continue coal deliveries from those suppliers and minimize the impacts of supply shortfall.

Q. Is PacifiCorp pursuing options under the coal supply agreements in response to coal suppliers' failure to deliver contracted coal quantities?

A. Yes. In accordance with the terms of the CSAs, PacifiCorp initiated arbitration to challenge the force majeure claim from one supplier. PacifiCorp continues to review options under the agreement with the second supplier because the second supplier's force majeure claim [redacted]

Q. How are PacifiCorp's coal facilities impacted by the coal supply constraints in Utah, and how has that been reflected for coal volumes in the 2024 TAM?

A. The coal supply constraints discussed above have resulted in lower than forecasted coal deliveries at both the Hunter and Huntington plants in late 2022 and early 2023. PacifiCorp's stockpiled inventories in Utah have been significantly depleted. PacifiCorp anticipates there will be a continuation of coal supply shortages and market instability in 2024. Therefore, PacifiCorp has adjusted its forecasts for tons of coal received and consumed in the 2024 TAM and has not assumed it can use any stockpiled inventory. The forecasted volumes of consumed coal in 2024 do not match the contracted volumes for coal in the CSAs for 2024. Furthermore, to ensure targeted coal inventory balances are available for reliability purposes, received and consumed coal quantities at the Utah plants are balanced in the 2024 TAM. The table below provides a comparison of 2022 actuals and the 2024 TAM direct filing for both Hunter and Huntington.

Plant	Received (mm tons)	Inventory Used (mm tons)	Consumed (mm tons)	Contracted (mm tons)
Hunter – 2022 Actuals	[redacted]	[redacted]	[redacted]	[redacted]
Hunter – 2024 TAM	[redacted]	[redacted]	[redacted]	[redacted]
Huntington – 2022 Actuals	[redacted]	[redacted]	[redacted]	[redacted]
Huntington – 2024 TAM	[redacted]	[redacted]	[redacted]	[redacted]

[2] [redacted]

Q. How has the increase in market coal prices impacted the 2024 TAM estimated fuel costs?

A. Although total coal fuel expense decreases in the 2024 TAM, coal prices on a per-ton basis increase significantly at some plants. Historically, the Company's prudent coal contracting practices have largely shielded the Company and its customers from significant, short-term coal price increases. The Company purchases coal from captive mines and third-party suppliers, typically under short- to medium-term contracts. Currently, due to the increased demand for coal in both foreign and domestic markets, coal suppliers have increased opportunities for coal sales. This has limited the volume of coal available for PacifiCorp. Most of the Company's coal contracts include fixed pricing provisions that do not escalate with general inflation. As a result, the impact of the increased coal pricing is largely contained to PacifiCorp plants with CSAs that terminate in 2022 or 2023, or where the Company was forced to respond to supplier force majeure claims. Specifically, the increased market prices are impacting 2024 pricing at the Black Butte mine which serves the Jim Bridger plant and the Wolverine, Gentry, and Bronco mines which serve the Hunter plant. These impacts are discussed in more detail later in my testimony.

IV. HUNTINGTON ENVIRONMENTAL PROVISION

Q. In docket UE 400 TAM Order No. 22-389, the Commission stated that [redacted]. How do you respond?

A. PacifiCorp would like to clarify the record on this issue. The Huntington CSA includes a specific clause that allows the Company to take Huntington CSA coal to the Hunter plant when a change in environmental regulation, defined as a Coal Consumption Event (CCE), affects the Company's ability to burn a minimum of [redacted] tons per contract year at the plant. The Huntington CSA does not include a general reopener or renegotiation clause. PacifiCorp has consistently noted that exercising the environmental regulations clause requires the occurrence of a CCE.[4] PacifiCorp has not previously had the ability to exercise this clause due to the lack of a qualifying CCE. Article VIII of the Huntington coal supply agreement further defines environmental regulation to include [redacted] At the time of both the 2021 and 2022 TAM filings, there were no qualifying events that could have triggered the

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[3] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-2389 at 6 (Oct. 25, 2022).

[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, PAC/500, Schwartz/23 (Jul. 9, 2021); *In the Matter of PacifiCorp d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, PAC/600, Ralston/26-30 (Jul. 9, 2021).

environmental provision in the contract. All PacifiCorp CSAs have some form of force majeure provisions to allow either party to be excused from performance of certain contract provisions due to external unforeseen events that have adverse effects on either the buyer or the supplier, such as government impositions or acts of God.

PacifiCorp discussed this force majeure position and the operation of this clause when the Commission reviewed the Deer Creek transaction in 2015. At the time, Company witness Cindy Crane noted, "The first paragraph of Article 8 describes a 'Coal Consumption Event' (CCE) and states that, if a CCE occurs, [redacted]"[5] In that testimony, Company witness Crane also noted, "Article 8 allows the Company to terminate if a regulation [redacted]" per year. Under Article 3 of the CSA, the Company's minimum requirement is [redacted] tons and its maximum requirement is [redacted] tons."[6]

Supplying the Hunter plant through the Huntington CSA in 2021 and 2022 was not possible because there was no environmental event or CCE to trigger the contract provision. Additionally, in actual operations, PacifiCorp burned 2.8 million

[5] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for Approval of the Deer Creek Mine Transaction*, Docket No. UM 1712, PAC/500, Crane/5 (Mar. 19, 2015).
[6] Docket No. UM 1712, PAC/500, Crane/6.

tons of coal in 2021 and 2.5 million tons of coal in 2022 at the Huntington plant, which [redacted]

Q. For the 2024 TAM, the Commission also directed PacifiCorp to provide projections for its Hunter contract, including an analysis of the appropriate minimum take and overall thermal fleet usage in multiple scenarios, including a scenario with no minimum take requirement. How did PacifiCorp meet this requirement?

A. The assumptions used for the model to determine the need for a new coal supply agreement included an estimated incremental price up to a given volume based on discussions with suppliers and did not include a minimum take constraint. This allowed the model to determine the optimal amount to select from the new potential source without minimum requirements. The model selected the full volume available from the new source, which validates the incremental pricing assumption used for the volume selected. This analysis is provided as Highly Confidential Exhibit PAC/201.

Q. For the 2024 TAM, the Commission stated that PacifiCorp's analysis for a new Hunter CSA "should include review of how additional flexibility in the Utah coal plants could be achieved in order to deliver the customer benefits described in the company's selection of the short list in docket UM 2059" which "linked the projected benefits of the Gateway South transmission capacity and Wyoming wind resources to the significant displacement of Hunter and Huntington coal generation beginning in 2025."[7] How did PacifiCorp meet this requirement?

A. The modeling that was conducted for a new Hunter coal supply included assumptions

[7] Order No. 22-389 at 7.

for the Gateway South transmission and wind renewables referred to in docket UM 2059. Specifically, "[redacted] The model selected all proposed coal supplies available at the Hunter plant and would have selected additional coal volumes if they were available in 2024 and 2025. The current low coal inventory levels at the Hunter plant provide further support for the need to procure additional coal supplies. PacifiCorp is also seeking to balance as much flexibility as possible against the costs of having this flexibility in negotiations with coal suppliers.

V. THIRD PARTY COAL CONTRACTS

Q. Has PacifiCorp entered into any new CSAs since it filed reply testimony in the 2023 TAM?

A. Yes. PacifiCorp has entered into new CSAs for the Wyodak plant (Wyodak CSA), for the Dave Johnston plant (Eagle Butte CSA), and for the Hunter plant (Gentry CSA). In addition, amendments have been signed for the Dave Johnston plant Caballo CSA (Caballo CSA) and for the Hunter plant Bronco CSA (Bronco CSA) and the Gentry CSA. Consistent with the requirements of the order from the 2023 TAM,[8] my testimony and the corresponding exhibits provide additional information demonstrating the prudence of these new and amended CSAs.

[8] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 6-7 (Nov. 1, 2021).

Q. Please discuss the change in overall third-party coal-supply costs in the 2024 TAM.

A. PacifiCorp expects a price variance net increase for the third-party coal-supply costs of [redacted], as shown in Confidential Table 2 below. The details of significant changes to costs are described for Black Butte later in my testimony, and further details are provided for Hunter below.

WYODAK COAL SUPPLY AGREEMENT

Q. Please provide some background on the Wyodak plant and the Wyodak CSA.

A. The Wyodak plant (Wyodak) is located in Campbell County, Wyoming and is jointly owned with Black Hills Energy (Black Hills), which has 20 percent ownership. There is one unit at the Wyodak plant that has an output capacity of 335 megawatts (MW). The Wyodak plant receives its coal from the adjacent Wyodak Mine by conveyor, thus eliminating the need to store coal inventory at the plant. Black Hills owns and operates the mine. PacifiCorp's prior agreement for Wyodak's coal supply terminated December 31, 2022. PacifiCorp executed the Wyodak CSA with the Wyodak Mine to supply coal to the plant through 2026.

Q. What are the key terms of the Wyodak CSA?

A. The duration of the Wyodak CSA is January 1, 2023 through December 31, 2026. This term is consistent with PacifiCorp's recent practice of limiting its CSAs to five years or less to maintain flexibility in fuel supply and generation planning. The price effective January 1, 2023, was [redacted] and is subject to adjustment each calendar month, based on specified indices for labor, materials and supplies, inflation, etc.

Q. Does the Wyodak CSA include a minimum take requirement?

A. No, the Wyodak CSA is a requirements agreement. Under a requirements agreement, the buyer agrees to purchase 100 percent of the buyer's coal fuel requirements for a particular plant from a single supplier. Under the Wyodak CSA, PacifiCorp made a commitment to purchase all the Wyodak plant's coal needs from Black Hills. As a joint owner of the plant, Black Hills is familiar with PacifiCorp's historical coal consumption. Due to Black Hills' unique understanding of and familiarity with the needs of the Wyodak plant, PacifiCorp was able to negotiate a contract without a contract minimum volume obligation. As I have stated in prior testimony, without some form of commitment by the buyer, a coal supplier, especially those which are captive in whole or in part to coal-fired power plants, cannot develop adequate mine permits and plans, project for capital and operating costs, or have an assured revenue stream for the coal they produce. In short, coal mines cannot operate without the ability to sell coal. In this case, the commitment was to make the supplier the sole source for the plant's coal supply.

DAVE JOHNSTON COAL SUPPLY AGREEMENT

Q. Please provide some background on the Dave Johnston plant and the Eagle Butte CSA.

A. The Dave Johnston plant is located in Glenrock, Wyoming, approximately 20 miles east of Casper, Wyoming. The plant is supplied by coal from multiple Powder River Basin (PRB) mines, and the coal is delivered by Burlington Northern Santa Fe rail. PacifiCorp owns and operates all four units at the plant. The output capacity at the plant is as follows: Unit 1: 106 MW; Unit 2 – 106 MW; Unit 3 – 220 MW; and

Unit 4 – 330 MW. PacifiCorp has executed the Eagle Butte CSA, operated by Eagle Specialty Materials, for a portion of the Dave Johnston coal supply through 2024. This contract was executed after performing an RFP process to identify the best available risk-adjusted price for additional coal for the Dave Johnston plant.

Q. What are the volume and pricing terms of the Eagle Butte CSA?

A. The annual volume and pricing are as follows:

Year	Quantity	Price/Ton
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]

Q. What contract terms were changed by the Caballo CSA amendment?

A. The original term for the Caballo CSA was January 1, 2021, through December 31, 2024. The first amendment to the Caballo CSA was entered into on December 21, 2022. It extended the term for another year, through December 31, 2025. The number of tons delivered for 2024 increased from [redacted] tons to [redacted] tons, and the annual tons to be delivered in 2025 is [redacted] tons. The Caballo CSA was amended after an RFP process (which was completed on May 31, 2022) to identify the best available risk-adjusted price for additional coal for the Dave Johnston plant.

HUNTER COAL SUPPLY AGREEMENT

Q. Please provide some background on the Hunter plant and the Gentry CSA.

A. The Hunter plant is located approximately 2.5 miles south of Castle Dale, Utah, in Emery County. The plant is supplied with coal from Wolverine Fuel Sales, LLC, Bronco Utah Operations, LLC and Gentry Mountain Mining, LLC. The coal is delivered to the plant by truck. PacifiCorp is the operator and majority owner of the Hunter plant. There are three units at the Hunter plant and the ownership is as follows:

- Unit 1: 94% PacifiCorp, 6% Utah Municipal Power Agency (UMPA)
- Unit 2: 60% PacifiCorp, 25% Deseret Power Electric Cooperative (DPEC), 15% Utah Associated Municipal Power Systems (UAMPS)
- Unit 3: 100% PacifiCorp

The output capacity at the plant is as follows: Units 1 and 2 – 446 MW; Unit 3 – 471 MW. PacifiCorp has executed a new CSA, the Gentry CSA, operated by Gentry Mountain Mining, LLC, to purchase additional coal for Hunter plant through 2025. This contract that provides for [redacted] to be delivered in 2023, 2024 and 2025 was executed on January 20, 2023, after performing an RFP process (which was completed on September 28, 2022) to identify the best available risk-adjusted price for additional coal for the Hunter plant. On February 1, 2023, the contract was further amended to increase the 2023 contract volume to [redacted].

Q. What are the volume and pricing terms of the Gentry CSA?

A. The annual volume and pricing are as follows:

Year	Quantity	Price/Ton
2023	[redacted]	[redacted]
2024		
2025		

Q. Does the Gentry CSA include a minimum take requirement?

A. Yes, the Gentry CSA is a take-or-pay agreement.

Q. What contract terms were changed by the Bronco CSA second amendment?

A. The second amendment for the Bronco CSA was signed on August 3, 2022. Bronco, the coal supplier, asserted that events and circumstances were in place that supported a declaration of force majeure and a complete suspension of their coal delivery obligations. PacifiCorp disagreed with Bronco and initiated arbitration processes, but also determined that a suspension of coal deliveries would result in significant disruptions to the Company's planned and expected generation of electricity at the Hunter Plant and lead to higher costs for customers. Because of the potential harmful consequences of a disruption of coal supply to the Hunter Plant, PacifiCorp and Bronco Utah Operations, LLC agreed to the second amendment to the Bronco CSA, which states that PacifiCorp would issue a new RFP in 2022 to secure a reliable and suitable coal supply for the Hunter Plant. In the interim, the two parties agreed to [redacted], if no RFP offer was deemed to provide a more prudent option. On November 29, 2022, PacifiCorp notified Bronco that it had completed the RFP process and deemed it in the best interests of the Company and customers to [redacted].

Q. Why did PacifiCorp execute a third amendment to the Bronco CSA?

A. After PacifiCorp notified the coal supplier of its intent to [redacted] of the Bronco CSA through the end of 2024, the coal supplier notified the Company that due to ongoing labor, market, and financial pressures, it was "unable to supply the Hunter Plant at the price offered" and expressed its intent to cease coal deliveries to the Company. PacifiCorp evaluated the potential unfavorable cost impacts to the Company and its customers that would result from the immediate loss of coal supply from the Bronco CSA. PacifiCorp engaged in negotiations with the supplier and ultimately agreed to a price increase under the third amendment, which ensured continued coal deliveries and was determined to be beneficial for the Company and its customers. [redacted]

Q. What are the volume and pricing terms of the Bronco CSA third amendment?

A. The annual volume and pricing are as follows:

Year	Quantity	Price/Ton
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]

Q. Please describe the change in delivered coal costs at the Hunter plant in the 2024 TAM.

A. The price of delivered coal from Bronco increased from [redacted] in the 2023 TAM to [redacted] in the 2024 TAM, and the price of delivered coal from [redacted] increased from [redacted] in the 2023 TAM to [redacted] in the 2024 TAM. These increases in price are the result of the force majeure circumstances described earlier in my testimony, and reflects the pricing received as a result of the RFP process.

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9 [redacted]

Q. The Commission directed PacifiCorp to hold a workshop with Parties within a reasonable time after the execution of the Hunter CSA. When will PacifiCorp be holding this workshop?

A. As I have noted above, there are significant coal supply constraints in Utah, and fueling the Hunter plant in 2024 will take place with at least three different coal supply agreements or amendments resulting from the recent RFP, one of which is still being negotiated. Once that CSA has been executed, PacifiCorp will reach out to Parties to schedule a workshop to walk through the complete coal supply arrangements at the Hunter plant.

NEW CSA ANALYSIS DOCUMENTATION

Q. In the order from the 2022 TAM, the Commission identified several elements that should be addressed when presenting a new CSA. What are those elements?

A. The 2022 order stated the following items should be addressed when PacifiCorp presents a new CSA:

- PacifiCorp will need to explain in detail how economic cycling was considered when deciding on minimum take levels in the contract, a comparison of the MMBtu level from generation analysis to the contracted-for level, and to provide the workpapers used in analysis of the generation forecasts for CSA negotiations.[10]

[10] Order No. 21-379 at 5.

- PacifiCorp will need to explain how it incorporates its integrated resource plan (IRP) planning into its TAM-reviewed fuel contracts, or its management of those contracts.[11]
- PacifiCorp will need to show it considered future costs in multiyear contracts, especially given that its plans for operating a plant generally would be expected to show declining production before retirement.[12]
- PacifiCorp will need to explain how it is allowing for an orderly sequence towards retirement and ensuring flexibility for reduced capacity factors and consumption of the coal pile, and how it will manage the contract in the event that circumstances change from those expected when it was signed.[13]

Q. Has PacifiCorp conducted an analysis for the Wyodak, Gentry, and Eagle Butte CSAs and the Bronco and Caballo amendments that involve these elements?

A. Yes. Please refer to Highly Confidential Exhibits PAC/201-204 which contain an overview and the background of the newly signed CSAs and amendments. These documents also describe in detail the economic analysis that PacifiCorp conducted to support the execution of the CSAs. Highly Confidential Exhibits PAC/201-204 demonstrates how PacifiCorp incorporated planning and modeling into the decision process relating to the new CSAs.

[11] *Id.* at 7.
[12] *Id.*
[13] *Id.*

Q. In the Commission's 2023 TAM Order, PacifiCorp was also directed that "information should include minimum take provisions and other key contract terms."[14] Has this information been included?

A. Yes.

Q. The Commission has also stated that "[w]hen a new CSA is under negotiation and thus only a forecast is incorporated in a TAM, the first-year anticipated nomination as well as estimations of the total cost forecast are necessary." Has this information been provided?

A. Yes, the CSAs under negotiation are shown with forecasted nominations in Confidential Table 1 below in the "Future Contracts" section. The full costs of these contracts are reflected in the workpapers.

VI. OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supply requirements for its coal plants in 2024?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 85.4 percent of its 2024 coal requirements with third-party coal supplies and 14.6 percent with coal from its captive affiliate mines. Within the third party contracts: (1) 51.3 percent of the total coal requirement will be supplied from fixed-price contracts; (2) 10.4 percent will be supplied under variable-priced contracts that increase or decrease based on changes to producer and consumer price indices; and (3) 23.7 percent of the total coal requirement will be supplied from contracts for the Jim Bridger, Hunter, and Dave

[14] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 at 5 (Oct. 25, 2022).

Johnston plants to be negotiated in 2023, which is further discussed in other sections of my testimony.

Confidential Table 1: Coal Source Deliveries

2024 Company/Mine	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]	14.6%
Fixed Price Contracts						
Wolverine/Sufco, Skyline	Huntington			[redacted]		
Bronco/Emery	Hunter			[redacted]		
Gentry Mountain/Gentry	Hunter		√	[redacted]		
Peabody/Twentymile	Hayden			[redacted]		
Peabody/NARM	Dave Johnston			[redacted]		
Peabody/Caballo	Dave Johnston			[redacted]		
Bluegrass/Eagle Butte	Dave Johnston		√	[redacted]		
Kemmerer Operations	Naughton			[redacted]		
Subtotal Fixed Price Contracts					[redacted]	51.3%
Variable Price Contracts						
Westmoreland/Rosebud	Colstrip			[redacted]		
Black Hills/Wyodak	Wyodak		√	[redacted]		
Subtotal Variable Price Contracts					[redacted]	10.4%
Future Contracts						
Wolverine/Sufco, Skyline	Hunter			[redacted]		
Lighthouse Resources/Black Butte	Jim Bridger			[redacted]		
Unspecified PRB Mines	Dave Johnston			[redacted]		
Total Other					[redacted]	23.7%
Total Coal Supplies					[redacted]	100%

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

Q. Has total coal-fuel expense in the 2024 TAM decreased from the level reflected in PacifiCorp's 2023 TAM?

A. Yes. Total coal-fuel expense has decreased by $91.5 million in the 2024 TAM. This decrease is the result of a $216.8 million volume reduction in coal-fired generation, partially offset by approximately $125.3 million in higher coal prices. These variances are shown in Confidential Table 2 below.

Confidential Table 2: Coal Fuel Variance - 2024 TAM vs. 2023 TAM

Plant	Contract			Millions ($)
Price Variance				
Affiliate Mines				
Jim Bridger	Bridger Coal Company	[redacted]		
Craig	Trapper Mining	[redacted]		
Subtotal Affiliate Mines			[redacted]	
Third-Party Contracts				
Naughton	Kemmerer Operations	[redacted]		
Wyodak	Wyodak Resources	[redacted]		
Dave Johnston	Powder River Basin	[redacted]		
Dave Johnston	BNSF	[redacted]		
Jim Bridger	Black Butte Coal	[redacted]		
Jim Bridger	UPRR	[redacted]		
Hunter	Wolverine Fuels	[redacted]		
Hunter	Bronco	[redacted]		
Hunter	Gentry Mountain	[redacted]		
Huntington	Wolverine Fuels	[redacted]		
Colstrip	Westmoreland	[redacted]		
Hayden	Peabody	[redacted]		
Subtotal Third-party Contracts			[redacted]	
Total Price Variance				$ 125.3
Volume Variance				
Jim Bridger		[redacted]		
Hunter		[redacted]		
Naughton		[redacted]		
Dave Johnston		[redacted]		
Craig		[redacted]		
Wyodak		[redacted]		
Other Plants		[redacted]		
Total Volume Variance				$ (216.8)
Total Coal Fuel Variance - Increase/(Decrease)				$ (91.5)

Q. Please provide an overview of the cost changes by supplier in the 2024 TAM.

A. The following tables compare values from the 2024 TAM Initial Filing versus the 2023 TAM Reply Filing. Confidential Table 3 shows updates to the CSA prices per ton received from each supplier:

Confidential Table 3

Cost Comparison by Coal Source						
Plant	Supplier	2024 TAM Direct	2023 TAM Reply	Variance $	Variance %	Variance Explanation
Colstrip	Westmoreland/Rosebud	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Craig	Trapper Mining Inc	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody/NARM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody/Caballo	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Unspecified PRB Mines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Eagle Butte	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	Peabody/Twentymile	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	Wolverine/Various	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	Bronco/Emery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	Gentry Mountain	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	Wolverine/Various	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	Lighthouse Resources/Black Butte	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	Bridger Coal Company	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	Kemmerer Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	Black Hills/Wyodak	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Confidential Table 4 compares the tons of coal consumed:

Confidential Table 4

Consumed Volume (tons, millions)				
Plant	**2024 TAM Direct**	**2023 TAM Reply**	**Variance-$**	**Variance-%**
Colstrip	[redacted]	[redacted]	[redacted]	[redacted]
Craig	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	[redacted]	[redacted]	[redacted]	[redacted]
Total	10.9	16.6	(5.7)	(34%)

Confidential Table 5 details the changes to total coal fuel costs:

Confidential Table 5

Fuel Cost ($,millions)				
Plant	**2024 TAM Direct**	**2023 TAM Reply**	**Variance-$**	**Variance-%**
Colstrip	[redacted]	[redacted]	[redacted]	[redacted]
Craig	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	[redacted]	[redacted]	[redacted]	[redacted]
Total	547.3	638.8	(91.5)	(14%)

Coal fuel costs have decreased by $91.5 million, driven mainly by a reduced coal generation forecast in the 2024 TAM Aurora results.

VII. JIM BRIDGER FUEL SUPPLY

A. Bridger Coal Company (BCC)

Q. Please briefly summarize the benefits for PacifiCorp customers which are associated with PacifiCorp's partial ownership of BCC.

A. Ownership in BCC allows PacifiCorp to flex coal deliveries up or down, within certain constraints, to better align Jim Bridger plant delivered and consumed coal quantities. Mine ownership also reduces coal supply delivery risk, mitigates unfavorable impacts of unexpected coal delivery changes, and has historically improved contract price terms with the third-party coal supplier.

Q. Please describe the change in BCC costs in the 2024 TAM.

A. BCC costs in the 2024 TAM are forecast to be [redacted] higher than the 2023 TAM. The cost for the base mine plan increased by [redacted] or [redacted], from [redacted] in the 2023 TAM to [redacted] in the 2024 TAM as shown in Confidential Table 3. The 2024 TAM assumes [redacted] base tons are delivered, which is [redacted] less tons delivered than in the 2023 TAM. In the 2024 TAM, the cost for supplemental coal decreases by [redacted], from [redacted] in the 2023 TAM to [redacted] in the 2024 TAM. Delivering [redacted] fewer tons results in an unfavorable supplemental price variance of [redacted].

Confidential Table 6: Jim Bridger Plant Coal Deliveries

	2024 TAM			2023 TAM Update			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 BCC mine costs increase by [redacted] in the 2024 TAM.

A. The cost increase is primarily due to delivering [redacted] tons in the 2024 TAM vs the 2023 TAM. The lower volume results in fixed mining costs being allocated to fewer tons, thus raising the cost per ton delivered.

Q. Has PacifiCorp identified a need to restock its inventory at the Jim Bridger facility?

A. As explained above, coal market conditions changed significantly beginning in late 2021 and those conditions continue to the current date. The changes had a significant impact on Jim Bridger plant operations and current coal inventory is significantly lower than the optimal amount targeted to ensure plant availability. PacifiCorp has optimized deliveries from the Company's Bridger Coal mine in 2024, and is [redacted]

Q. In the stipulation approved by the Commission in the 2023 TAM, PacifiCorp has been required to provide the updated annual BCC mine plan. Has this document been provided in the workpapers to this filing?

A. Yes, this document has been provided in my highly confidential workpapers.

Q. In Order No. 13-387, the Commission ordered the Company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate captive mines.[15] In this filing, does PacifiCorp adjust the price of coal from BCC consistent with this order?

A. Yes. In the 2024 TAM the Company reduces BCC costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

B. Jim Bridger Third-Party Coal Supply

Q. What is the expected change in third-party coal prices for the Jim Bridger plant in the 2024 TAM?

A. Delivered costs for the [redacted] of Black Butte coal increased from [redacted] in the 2023 TAM to [redacted] in the 2024 TAM, or [redacted] overall. The Black Butte price for 2024 assumed a lower minimum volume which resulted in a higher cost per ton estimate of [redacted] based on indicative pricing received from the vendor, and the price for 2023 was estimated at [redacted] as per the pricing terms of the CSA signed in 2022. The estimate for 2024 will be updated if a new contract is executed prior to the TAM update submittal deadline. The estimated costs for delivery of coal from Black Butte is forecasted to decrease by $0.1 million in delivered costs.

Q. Why are you assuming that PacifiCorp will execute a new CSA with Black Butte for 2024?

A. Continued coal shortages that are occurring in 2023 and that are projected to continue

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

into 2024 indicate the need for a CSA with Black Butte in 2024. A full analysis will be performed later in 2023 to determine the prudence of executing a new Black Butte agreement, and any changes as a result of the analysis will be reflected in the TAM update.

Q. Why is executing a new Black Butte CSA necessary to address coal shortages at the Jim Bridger plant?

A. The Jim Bridger plant inventory levels have declined since the latter half of 2022 and are projected to further decline below target levels intended to maintain availability at the plant. Without coal supplied by Black Butte in 2024, it would not be possible to restore inventory levels to prudent operating levels.

Q. If the Long-Term Fuel Plan and analysis in the IRP shows that it is uneconomic to pursue a short-term contract with Black Butte, will PacifiCorp still pursue a new CSA with Black Butte?

A. No.

VIII. CONCLUSION

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

A. Customers have significantly benefited from PacifiCorp's prudent and 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. The overall decrease in coal-fuel expense in this filing has been primarily driven down by reduced coal volumes, as shown in Confidential Table 2 above. PacifiCorp's fixed price coal contracts have continued to benefit customers as natural gas and power prices rise. However, the demand and cost for coal has increased both nationally and globally, and PacifiCorp continues to work with its coal suppliers and mines to ensure the best risk-adjusted pricing for the benefit of our customers.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 420
Exhibit PAC/201
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of James Owen

Hunter/Gentry CSA Analysis

April 2023

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

REDACTED
Docket No. UE 420
Exhibit PAC/202
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of James Owen

Dave Johnston CSA Analysis

April 2023

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REDACTED
Docket No. UE 420
Exhibit PAC/203
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of James Owen

Wyodak CSA Analysis

April 2023

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REDACTED
Docket No. UE 420
Exhibit PAC/204
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of James Owen

Hunter/Bronco CSA Analysis

April 2023

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Docket No. UE 420
Exhibit PAC/205
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of James Owen

CSA Contract Minimums Table

April 2023

Confidential: Coal Supply Agreement Contract Minimums
(all figures are in tons of coal)

Plant	Coal Mine	Contractual Minimum	2024 TAM Forecast Deliveries	Minimum %
Colstrip	Rosebud	[redacted]		
Craig	Trapper			
Dave Johnston	North Antelope Rochelle			
Dave Johnston	Eagle Butte			
Dave Johnston	Caballo-Contract 2			
Dave Johnston Total				
Hayden	Twentymile			
Hunter	Wolverine			
Hunter	Gentry			
Hunter	Bronco			
Hunter Total				
Huntington	Wolverine[1]			
Jim Bridger	Black Butte			
Jim Bridger	Bridger			
Jim Bridger Total				
Naughton	Kemmerer			
Wyodak	Wyodak			

Notes
1. As described in testimony, force majuere claim by supplier has impacted contractual minimum.
Forecast numbers provided are from 2024 TAM initial filing

Docket No. UE 420
Exhibit PAC/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

April 2023

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 2024 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and other amounts identified by Mr. Ramon J. Mitchell. 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 the TAM.

A. PacifiCorp collects the TAM through Schedule 201, Net Power Costs, Cost-Based Supply Service. Collecting the TAM 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 stand-alone TAM is the year during which the Schedule 201 rates will be effective, which is the forecast 12 months ending December 31, 2024.

Q. How did the Company allocate the proposed TAM revenues to the rate schedule classes?

A. PacifiCorp allocated proposed TAM revenues to the rate schedules based on the present spread of TAM revenues. This is consistent with the TAM Guidelines and the generation allocation in the Company's last general rate case, docket UE 399, updated for the change in load.

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

A. Yes. Exhibit PAC/301 shows the TAM rate spread and revenue targets along with the present and proposed Schedule 201 rates and revenues. As explained by Mr. Mitchell, forecast NPC is subject to updates throughout this proceeding.

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

A. Yes. The proposed Schedule 201 rates are designed to collect revenues from rate

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

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 the existing Schedule 201 rates.

Q. Are changes necessary in the 2024 TAM to Schedule 205 related to TAM Adjustment for Other Revenues?

A. No. PacifiCorp's Schedule 205, TAM Adjustment for Other Revenues, has been used to collect or distribute the adjustment related to other revenues in a stand-alone TAM filing. No adjustment is required as part of this filing and the rates are currently zero.

Q. Please describe Exhibit PAC/302.

A. Exhibit PAC/302 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 increase of $163.8 million or 9.5 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/303 shows the estimated effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Fund (Schedule 91), Low Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

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/303, beginning on page two, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Fund (Schedule 91), Low Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

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

A. The estimated average monthly impact to the average residential customer using

900 kilowatt-hours per month is a bill increase of $9.58.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 420
Exhibit PAC/301
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

April 2023

PACIFIC POWER
STATE OF OREGON
Schedule 201 - Net Power Costs - Cost-Based Supply Service
Proposed Rate and Revenue Adjustments
Forecast 12 Months Ended December 31, 2024

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Generation Rate Spread	Target Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 4, Residential							
All kWh	5,829,080,761	3.269 ¢	$190,552,650	37.3825%	$251,704,065	4.318 ¢	$251,699,707
	5,829,080,761		$190,552,650		$251,704,065		$251,699,707
Employee Discount							
All kWh	13,481,008	3.269	$440,694			4.318 ¢	$582,110
	13,481,008		$440,694				$582,110
Discount			-$110,174		-$145,528		-$145,528
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	911,866,507	3.262 ¢	$29,745,085	5.8354%	$39,290,762	4.309 ¢	$39,292,328
All additional kWh, per kWh	251,083,824	2.418 ¢	$6,071,207	1.1910%	$8,019,555	3.194 ¢	$8,019,617
	1,162,950,331		$35,816,292		$47,310,317		$47,311,945
Primary Voltage							
1st 3,000 kWh, per kWh	1,848,595	3.163 ¢	$58,471	0.0115%	$77,235	4.178 ¢	$77,234
All additional kWh, per kWh	1,551,757	2.346 ¢	$36,404	0.0071%	$48,087	3.099 ¢	$48,089
	3,400,352		$94,875		$125,322		$125,323
Schedule 28, General Service 31-200kW							
Secondary Voltage							
All kWh, per kWh	2,059,282,012	3.041 ¢	$62,622,766	12.2853%	$82,719,420	4.017 ¢	$82,721,358
	2,059,282,012		$62,622,766		$82,719,420		$82,721,358
Primary Voltage							
All kWh, per kWh	24,744,600	2.971 ¢	$735,162	0.1442%	$971,087	3.924 ¢	$970,978
	24,744,600		$735,162		$971,087		$970,978
Schedule 29 TOU Pilot, untiered, per kWh		*3.837 ¢*				*5.068 ¢*	
Schedule 30, General Service 201-999kW							
Secondary Voltage							
All kWh, per kWh	1,223,348,242	2.982 ¢	$36,480,245	7.1567%	$48,187,343	3.939 ¢	$48,187,687
	1,223,348,242		$36,480,245		$48,187,343		$48,187,687
Primary Voltage							
All kWh, per kWh	101,732,550	2.972 ¢	$3,023,491	0.5931%	$3,993,778	3.926 ¢	$3,994,020
	101,732,550		$3,023,491		$3,993,778		$3,994,020
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
All kWh, per kWh	237,609,947	2.938 ¢	$6,980,980	1.3695%	$9,221,289	3.881 ¢	$9,221,642
	237,609,947		$6,980,980		$9,221,289		$9,221,642
Primary Voltage							
All kWh, per kWh	34,304	2.893 ¢	$992	0.0002%	$1,310	3.820 ¢	$1,310
	34,304		$992		$1,310		$1,310
Net TOU Adders			-$636		-$636		-$636
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	6,937,804	3.480 ¢	$241,436			4.597 ¢	$318,931
Off-Peak, per off-peak kWh	9,669,725	2.471 ¢	$238,939			3.264 ¢	$315,620
	16,607,529		$480,375		$634,551		$634,551
Transmission Voltage							
On-Peak, per on-peak kWh	5,163,458	3.370 ¢	$174,009			4.451 ¢	$229,826
Off-Peak, per off-peak kWh	9,129,839	2.344 ¢	$214,003			3.096 ¢	$282,660
	14,293,297		$388,012		$512,486		$512,486

PACIFIC POWER
STATE OF OREGON
Schedule 201 - Net Power Costs - Cost-Based Supply Service
Proposed Rate and Revenue Adjustments
Forecast 12 Months Ended December 31, 2024

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Generation Rate Spread	Target Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 48, Large General Service, 1,000kW and over							
Secondary Voltage							
On-Peak, per on-peak kWh	463,483,442	3.577 ¢	$16,578,803	3.2524%	$21,899,208	4.725 ¢	$21,899,593
Off-Peak, per off-peak kWh	752,720,550	2.578 ¢	$19,405,136	3.8069%	$25,632,557	3.405 ¢	$25,630,135
	1,216,203,992		$35,983,939		$47,531,765		$47,529,728
Primary Voltage							
On-Peak, per on-peak kWh	936,940,456	3.480 ¢	$32,605,528	6.3965%	$43,069,167	4.597 ¢	$43,071,153
Off-Peak, per off-peak kWh	1,536,799,519	2.471 ¢	$37,974,316	7.4498%	$50,160,886	3.264 ¢	$50,161,136
	2,473,739,975		$70,579,844		$93,230,053		$93,232,289
Transmission Voltage							
On-Peak, per on-peak kWh	915,695,287	3.370 ¢	$30,858,931	6.0539%	$40,762,059	4.451 ¢	$40,757,597
Off-Peak, per off-peak kWh	1,517,786,997	2.344 ¢	$35,576,927	6.9795%	$46,994,136	3.096 ¢	$46,990,685
	2,433,482,284		$66,435,858		$87,756,195		$87,748,282
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	8,050,392	1.035 ¢	$83,284	0.0163%	$110,011	1.368 ¢	$110,151
	8,050,392		$83,284				$110,151
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	21,063,034	1.216 ¢	$256,137	0.0502%	$338,336	1.610 ¢	$339,137
	21,063,034		$256,137				$339,137
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	7,518,996	1.021 ¢	$76,769	0.0151%	$101,405	1.349 ¢	$101,431
	7,518,996		$76,769				$101,431
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,393,660	1.021 ¢	$14,229	0.0028%	$18,795	1.349 ¢	$18,800
	1,393,660		$14,229				$18,800
Total before Employee Discount			**$510,605,264**	**100.0000%**	**$674,466,893**		**$674,460,189**
Employee Discount			-$110,174		-$145,528		-$145,528
TOTAL	**16,834,536,258**		**$510,495,090**		**$674,321,365**		**$674,314,662**
						Change	**$163,819,572**
Schedule 47 Unscheduled kWh	1,362,310						
Total Forecast kWH	16,835,898,568						

Docket No. UE 420
Exhibit PAC/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule

April 2023

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	All kWh, per kWh		4.318¢			(I)
5	All kWh, per kWh		4.318¢			(I)
6	Per kWh	All kWh	4.318¢			(I)
	plus	per On-Peak kWh	14.270¢			
	plus	per Off-Peak kWh (credit)	-3.790¢			

For Schedule 6, On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours.

23	First 3,000 kWh, per kWh	4.309¢	4.178¢	(I)
	All additional kWh, per kWh	3.194¢	3.099¢	(I)
28	All kWh, per kWh	4.017¢	3.924¢	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage: Secondary	Primary	Transmission	
29	All kWh, per kWh	5.068¢	5.068¢		(I)
	Plus per Off-Peak kWh (credit)	-0.739¢	-0.739¢		

For Schedule 29, Summer On-Peak hours are from 4 p.m. to 8 p.m. Monday through Friday excluding holidays in the Summer months of April through October. Non-Summer On-Peak hours are from 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m. Monday through Friday excluding holidays in the Non-Summer months of November through March. Off-Peak hours are all remaining hours.

		Secondary	Primary	Transmission	
30	All kWh, per kWh	3.939¢	3.926¢		(I)
41	All kWh, per kWh	3.881¢	3.820¢		(I)
	Optional TOU Adders				
	Plus per On-Peak kWh	4.989¢	4.989¢		
	Plus per Off-Peak kWh (credit)	-0.992¢	-0.992¢		

Schedule 41 Consumers may choose to participate in one of two Time-of-Use (TOU) rate options, Option A and Option B which provide time-varying rates in the Summer months of July, August and September. Consumers may choose to participate in Option A with On-Peak hours from 2 p.m. to 6 p.m. all days in Summer or Option B with On-Peak hours from 6 p.m. to 10 p.m. all days in Summer. Off-peak hours for each Option are all other Summer hours which are not On-Peak. All other months have no time-of-use periods or rate adders.

		Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	4.725¢	4.597¢	4.451¢	(I)
	Per kWh, Off-Peak	3.405¢	3.264¢	3.096¢	(I)

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. Off-Peak hours are all remaining hours.

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
	Level 1	0-5,000	19	$1.02	(I)
	Level 2	5,001-12,000	34	$1.82	(I)
	Level 3	12,001+	57	$3.05	(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

NET POWER COSTS
COST-BASED SUPPLY SERVICE

Monthly Billing (continued)

Delivery Service Schedule No.

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51	Level 1	0-3,500	8	$0.37	(I)
	Level 2	3,501-5,500	15	$0.69	
	Level 3	5,501-8,000	25	$1.14	
	Level 4	8,001-12,000	34	$1.56	
	Level 5	12,001-15,500	44	$2.02	
	Level 6	15,501+	57	$2.62	(I)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53	High Pressure Sodium	5,800	70	31	$0.42	(I)
	High Pressure Sodium	9,500	100	44	$0.59	
	High Pressure Sodium	16,000	150	64	$0.86	
	High Pressure Sodium	22,000	200	85	$1.15	
	High Pressure Sodium	27,500	250	115	$1.55	
	High Pressure Sodium	50,000	400	176	$2.37	
	Metal Halide	9,000	100	39	$0.53	
	Metal Halide	12,000	175	68	$0.92	
	Metal Halide	19,500	250	94	$1.27	
	Metal Halide	32,000	400	149	$2.01	
	Metal Halide	107,800	1,000	354	$4.78	(I)
	Non-Listed Luminaire, per kWh				1.349¢	(I)

54	Per kWh	1.349¢	(I)

(continued)

Docket No. UE 420
Exhibit PAC/303
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

April 2023

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, 2024

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	540,041	5,829,081	$737,548	$8,977	$746,525	$798,695	$8,977	$807,672	$61,147	8.3%	$61,147	8.2%	1
2	**Total Residential**		540,041	5,829,081	$737,548	$8,977	$746,525	$798,695	$8,977	$807,672	$61,147	8.3%	$61,147	8.2%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	85,313	1,166,351	$149,483	$2,496	$151,978	$161,009	$2,496	$163,504	$11,526	7.7%	$11,526	7.6%	3
4	Gen. Svc. 31 - 200 kW	28	10,587	2,084,027	$186,116	$20,590	$206,706	$206,451	$20,590	$227,041	$20,334	10.9%	$20,334	9.8%	4
5	Gen. Svc. 201 - 999 kW	30	872	1,325,081	$105,890	$12,417	$118,307	$118,568	$12,417	$130,985	$12,678	12.0%	$12,678	10.7%	5
6	Large General Service >= 1,000 kW	48	182	6,123,426	$435,177	$16,877	$452,053	$490,687	$16,877	$507,564	$55,511	12.7%	$55,511	12.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	32,263	$4,320	$88	$4,409	$4,599	$88	$4,687	$279	12.7%	$279	12.2%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,219	$111	$1,329	$1,219	$111	$1,329	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	7,913	237,644	$30,384	($2,916)	$27,468	$32,625	($2,916)	$29,709	$2,241	7.4%	$2,241	8.2%	9
10	**Total Commercial & Industrial**		104,874	10,968,792	$912,589	$49,663	$962,251	$1,015,158	$49,663	$1,064,820	$102,569	11.2%	$102,569	10.7%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,703	8,050	$788	$242	$1,031	$815	$242	$1,058	$27	3.4%	$27	2.6%	11
12	Street Lighting Service Comp. Owned	51	1,121	21,063	$2,715	$933	$3,648	$2,798	$933	$3,731	$83	3.1%	$83	2.3%	12
13	Street Lighting Service Cust. Owned	53	292	7,519	$392	$221	$613	$417	$221	$637	$25	6.3%	$25	4.0%	13
14	Recreational Field Lighting	54	100	1,394	$88	$52	$140	$92	$52	$144	$5	5.2%	$5	3.3%	14
15	**Total Public Street Lighting**		7,215	38,026	$3,983	$1,448	$5,431	$4,122	$1,448	$5,570	$139	3.5%	$139	2.6%	15
16	**Subtotal**		652,131	16,835,899	$1,654,120	$60,087	$1,714,207	$1,817,975	$60,087	$1,878,062	$163,855	9.9%	$163,855	9.6%	16
17	Emplolyee Discount		*975*	*13,481*	($419)	($5)	($424)	($455)	($5)	($460)	($35)		($35)		17
17	Paperless Credit				($2,072)		($2,072)	($2,072)		($2,072)	$0		$0		17
18	AGA Revenue				$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization				$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**		652,131	16,835,899	$1,656,916	$60,082	$1,716,998	$1,820,736	$60,082	$1,880,818	$163,820	9.9%	$163,820	9.5%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Fund (Sch. 91), Low Income Discount Cost Recovery Adjustment (Sch. 92), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

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

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$24.02	$25.09	$1.07	4.45%
200	$35.49	$37.62	$2.13	6.00%
300	$46.97	$50.17	$3.20	6.81%
400	$58.45	$62.71	$4.26	7.29%
500	$69.92	$75.24	$5.32	7.61%
600	$81.40	$87.79	$6.39	7.85%
700	$92.88	$100.33	$7.45	8.02%
800	$104.36	$112.87	$8.51	8.15%
900	**$115.83**	**$125.41**	**$9.58**	**8.27%**
1,000	$127.30	$137.95	$10.65	8.37%
1,100	$138.78	$150.50	$11.72	8.45%
1,200	$150.25	$163.03	$12.78	8.51%
1,300	$161.73	$175.57	$13.84	8.56%
1,400	$173.21	$188.12	$14.91	8.61%
1,500	$184.68	$200.65	$15.97	8.65%
1,600	$196.16	$213.19	$17.03	8.68%
2,000	$242.06	$263.36	$21.30	8.80%
3,000	$366.55	$398.50	$31.95	8.72%
4,000	$491.04	$533.63	$42.59	8.67%
5,000	$615.53	$668.77	$53.24	8.65%

* Net rate including Schedules 91, 92, 98, 290 and 291.

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

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.98	$22.04	$1.06	5.05%
200	$32.45	$34.58	$2.13	6.56%
300	$43.93	$47.12	$3.19	7.26%
400	$55.41	$59.66	$4.25	7.67%
500	$66.87	$72.20	$5.33	7.97%
600	$78.35	$84.74	$6.39	8.16%
700	$89.83	$97.29	$7.46	8.30%
800	$101.31	$109.83	$8.52	8.41%
900	$112.78	$122.36	$9.58	8.49%
1,000	$124.26	$134.91	$10.65	8.57%
1,100	$135.74	$147.45	$11.71	8.63%
1,200	$147.21	$159.98	$12.77	8.67%
1,300	$158.69	$172.53	$13.84	8.72%
1,400	$170.17	$185.07	$14.90	8.76%
1,500	$181.63	$197.61	$15.98	8.80%
1,600	$193.11	$210.15	$17.04	8.82%
2,000	$239.02	$260.31	$21.29	8.91%
3,000	$363.51	$395.45	$31.94	8.79%
4,000	$488.00	$530.59	$42.59	8.73%
5,000	$612.49	$665.73	$53.24	8.69%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
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	$78	$87	$84	$92	6.77%	6.09%
	750	$109	$118	$117	$126	7.32%	6.78%
	1,000	$139	$148	$150	$159	7.63%	7.17%
	1,500	$200	$209	$216	$225	7.96%	7.63%
10	1,000	$139	$148	$150	$159	7.63%	7.17%
	2,000	$261	$270	$282	$291	8.14%	7.88%
	3,000	$383	$392	$415	$423	8.33%	8.14%
	4,000	$489	$497	$528	$537	8.14%	7.99%
20	4,000	$524	$533	$564	$573	7.58%	7.46%
	6,000	$736	$745	$792	$800	7.54%	7.45%
	8,000	$948	$957	$1,019	$1,028	7.52%	7.45%
	10,000	$1,160	$1,168	$1,247	$1,255	7.50%	7.45%
30	9,000	$1,125	$1,134	$1,204	$1,213	7.03%	6.98%
	12,000	$1,443	$1,451	$1,546	$1,554	7.12%	7.08%
	15,000	$1,760	$1,769	$1,887	$1,895	7.18%	7.15%
	18,000	$2,078	$2,086	$2,228	$2,237	7.22%	7.19%

* Net rate including Schedules 91, 92, 290 and 291.

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

		Monthly Billing*				Percent Difference	
kW		Present Price		Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$77	$86	$82	$91	6.66%	5.99%
	750	$107	$116	$115	$124	7.21%	6.67%
	1,000	$137	$146	$147	$156	7.52%	7.07%
	1,500	$197	$205	$212	$221	7.85%	7.52%
10	1,000	$137	$146	$147	$156	7.52%	7.07%
	2,000	$256	$265	$277	$286	8.03%	7.77%
	3,000	$376	$385	$407	$415	8.22%	8.04%
	4,000	$480	$488	$518	$527	8.04%	7.89%
20	4,000	$515	$524	$554	$562	7.48%	7.36%
	6,000	$723	$732	$777	$786	7.45%	7.36%
	8,000	$931	$939	$1,000	$1,009	7.43%	7.36%
	10,000	$1,139	$1,147	$1,223	$1,232	7.41%	7.36%
30	9,000	$1,106	$1,114	$1,182	$1,191	6.94%	6.89%
	12,000	$1,417	$1,426	$1,517	$1,526	7.03%	6.99%
	15,000	$1,729	$1,738	$1,852	$1,860	7.09%	7.06%
	18,000	$2,041	$2,049	$2,186	$2,195	7.13%	7.10%

* Net rate including Schedules 91, 92, 290 and 291.

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$366	$396	8.12%
	4,500	$485	$530	9.19%
	7,500	$724	$798	10.26%
31	6,200	$737	$798	8.34%
	9,300	$983	$1,076	9.37%
	15,500	$1,477	$1,630	10.40%
40	8,000	$945	$1,024	8.38%
	12,000	$1,264	$1,382	9.41%
	20,000	$1,900	$2,098	10.43%
60	12,000	$1,410	$1,529	8.43%
	18,000	$1,887	$2,066	9.45%
	30,000	$2,842	$3,139	10.46%
80	16,000	$1,868	$2,027	8.48%
	24,000	$2,505	$2,743	9.49%
	40,000	$3,778	$4,174	10.49%
100	20,000	$2,327	$2,525	8.52%
	30,000	$3,122	$3,420	9.52%
	50,000	$4,714	$5,209	10.51%
200	40,000	$4,595	$4,992	8.62%
	60,000	$6,187	$6,781	9.61%
	100,000	$9,370	$10,361	10.57%

* Net rate including Schedules 91, 92, 290 and 291.

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$448	$491	9.72%
	6,000	$560	$618	10.37%
	7,500	$671	$744	10.80%
31	9,300	$906	$996	9.93%
	12,400	$1,137	$1,257	10.55%
	15,500	$1,368	$1,518	10.96%
40	12,000	$1,163	$1,279	9.98%
	16,000	$1,462	$1,617	10.59%
	20,000	$1,760	$1,954	10.99%
60	18,000	$1,737	$1,911	10.02%
	24,000	$2,185	$2,417	10.63%
	30,000	$2,632	$2,922	11.02%
80	24,000	$2,305	$2,537	10.07%
	32,000	$2,902	$3,212	10.67%
	40,000	$3,499	$3,886	11.06%
100	30,000	$2,874	$3,164	10.10%
	40,000	$3,620	$4,007	10.69%
	50,000	$4,366	$4,850	11.08%
200	60,000	$5,696	$6,276	10.19%
	80,000	$7,188	$7,962	10.77%
	100,000	$8,680	$9,647	11.14%

* Net rate including Schedules 91, 92, 290 and 291.

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$2,795	$2,989	6.95%
	30,000	$3,363	$3,655	8.66%
	50,000	$4,500	$4,986	10.79%
200	40,000	$5,148	$5,536	7.55%
	60,000	$6,284	$6,867	9.27%
	100,000	$8,557	$9,529	11.35%
300	60,000	$7,658	$8,240	7.61%
	90,000	$9,362	$10,237	9.34%
	150,000	$12,772	$14,229	11.41%
400	80,000	$10,054	$10,831	7.73%
	120,000	$12,327	$13,492	9.46%
	200,000	$16,873	$18,816	11.51%
500	100,000	$12,482	$13,454	7.78%
	150,000	$15,324	$16,781	9.51%
	250,000	$21,007	$23,435	11.56%
600	120,000	$14,911	$16,077	7.82%
	180,000	$18,321	$20,069	9.54%
	300,000	$25,140	$28,054	11.59%
800	160,000	$19,768	$21,323	7.86%
	240,000	$24,315	$26,646	9.59%
	400,000	$33,407	$37,293	11.63%
1000	200,000	$24,626	$26,568	7.89%
	300,000	$30,309	$33,223	9.61%
	500,000	$41,647	$46,504	11.66%

* Net rate including Schedules 91, 92, 290 and 291.

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

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,318	$3,608	8.76%
	40,000	$3,882	$4,269	9.98%
	50,000	$4,446	$4,930	10.89%
200	60,000	$6,220	$6,801	9.34%
	80,000	$7,349	$8,123	10.54%
	100,000	$8,477	$9,445	11.42%
300	90,000	$9,265	$10,136	9.41%
	120,000	$10,958	$12,120	10.60%
	150,000	$12,650	$14,103	11.48%
400	120,000	$12,237	$13,398	9.50%
	160,000	$14,493	$16,043	10.69%
	200,000	$16,750	$18,687	11.56%
500	150,000	$15,210	$16,663	9.55%
	200,000	$18,031	$19,968	10.74%
	250,000	$20,852	$23,273	11.61%
600	180,000	$18,184	$19,927	9.59%
	240,000	$21,569	$23,893	10.77%
	300,000	$24,954	$27,859	11.64%
800	240,000	$24,131	$26,455	9.63%
	320,000	$28,645	$31,743	10.82%
	400,000	$33,159	$37,032	11.68%
1000	300,000	$30,078	$32,983	9.66%
	400,000	$35,721	$39,594	10.84%
	500,000	$41,335	$46,177	11.71%

* Net rate including Schedules 91, 92, 290 and 291.

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

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	2,000	$200	$174	$219	$174	9.58%	0.00%
	3,000	$300	$174	$328	$174	9.58%	0.00%
	5,000	$499	$174	$547	$174	9.58%	0.00%
Three Phase							
20	4,000	$400	$347	$438	$347	9.58%	0.00%
	6,000	$599	$347	$657	$347	9.58%	0.00%
	10,000	$999	$347	$1,095	$347	9.58%	0.00%
100	20,000	$1,998	$1,604	$2,189	$1,604	9.58%	0.00%
	30,000	$2,996	$1,604	$3,284	$1,604	9.58%	0.00%
	50,000	$4,994	$1,604	$5,473	$1,604	9.58%	0.00%
300	60,000	$5,993	$3,980	$6,567	$3,980	9.58%	0.00%
	90,000	$8,989	$3,980	$9,851	$3,980	9.58%	0.00%
	150,000	$14,982	$3,980	$16,418	$3,980	9.58%	0.00%

* Net rate including Schedules 91, 92, 98, 290 and 291.

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

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	3,000	$294	$172	$323	$172	9.59%	0.00%
	4,000	$392	$172	$430	$172	9.59%	0.00%
	5,000	$490	$172	$538	$172	9.59%	0.00%
Three Phase							
20	6,000	$589	$343	$645	$343	9.59%	0.00%
	8,000	$785	$343	$860	$343	9.59%	0.00%
	10,000	$981	$343	$1,075	$343	9.59%	0.00%
100	30,000	$2,943	$1,573	$3,225	$1,573	9.59%	0.00%
	40,000	$3,924	$1,573	$4,300	$1,573	9.59%	0.00%
	50,000	$4,905	$1,573	$5,375	$1,573	9.59%	0.00%
300	90,000	$8,828	$3,909	$9,675	$3,909	9.59%	0.00%
	120,000	$11,771	$3,909	$12,900	$3,909	9.59%	0.00%
	150,000	$14,714	$3,909	$16,125	$3,909	9.59%	0.00%

* Net rate including Schedules 91, 92, 98, 290 and 291.

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

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$29,758	$32,648	9.71%
	500,000	$42,017	$46,835	11.47%
	700,000	$54,020	$60,765	12.49%
2,000	600,000	$58,757	$64,539	9.84%
	1,000,000	$80,935	$90,780	12.16%
	1,400,000	$104,018	$117,801	13.25%
6,000	1,800,000	$160,846	$178,566	11.02%
	3,000,000	$230,095	$259,629	12.84%
	4,200,000	$299,344	$340,692	13.81%
12,000	3,600,000	$319,350	$354,791	11.10%
	6,000,000	$457,848	$516,916	12.90%
	8,400,000	$596,346	$679,042	13.87%

Notes:

On-Peak kWh	38.11%
Off-Peak kWh	61.89%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

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

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$28,147	$30,936	9.91%
	500,000	$40,172	$44,819	11.57%
	700,000	$51,940	$58,447	12.53%
2,000	600,000	$55,546	$61,123	10.04%
	1,000,000	$77,175	$86,672	12.30%
	1,400,000	$99,779	$113,074	13.32%
6,000	1,800,000	$157,538	$174,631	10.85%
	3,000,000	$225,349	$253,838	12.64%
	4,200,000	$293,160	$333,044	13.60%
12,000	3,600,000	$312,765	$346,951	10.93%
	6,000,000	$448,387	$505,364	12.71%
	8,400,000	$584,009	$663,777	13.66%

Notes:

On-Peak kWh	37.88%
Off-Peak kWh	62.12%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

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

kW Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	500,000	$38,289	$42,734	11.61%
	700,000	$49,620	$55,843	12.54%
2,000	1,000,000	$73,182	$82,264	12.41%
	1,400,000	$94,893	$107,609	13.40%
6,000	3,000,000	$216,614	$243,861	12.58%
	4,200,000	$281,749	$319,894	13.54%
12,000	6,000,000	$430,659	$485,152	12.65%
	8,400,000	$560,928	$637,219	13.60%

Notes:

On-Peak kWh	37.63%
Off-Peak kWh	62.37%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.