MCDOWELL RACKNER GIBSON PC
419 SW 11th Ave, Suite 400 | Portland, OR 97205

KATHERINE MCDOWELL
Direct (503) 595-3924
katherine@mrg-law.com

September 1, 2023

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97308-1088

Re: UE 420 – *In the Matter of PACIFICORP, dba PACIFIC POWER, 2024 Transition Adjustment Mechanism.*

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp dba Pacific Power's Exhibit List and Cross Examination Exhibits. Confidential material in support of this 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. 23-211.

Please contact this office with any questions.

Sincerely,

Katherine McDowell

Attachments

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of the confidential and highly confidential pages of PacifiCorp's **Exhibit List and Cross-Examination Exhibits** on the parties listed below that have signed the protective order(s) via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 420

AWEC	
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M ADAMS **(C)** **(HC)** RICHARDSON ADAMS, PLLC 515 N 27th ST BOISE ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

KWUA	
KWUA KLAMATH WATER USER ASSOCIATION KLAMATH BASIN WATER USER PROTECTIVE ASSOCIATION 2312 SOUTH SIXTH ST, STE A KLAMATH FALLS, OR 97601 assist@kwua.org	PAUL S SIMMONS **(C)** **(HC)** SOMACH SIMMONS & DUNN 500 CAPITOL MALL STE 1000 SACRAMENTO CA 95814 psimmons@somachlaw.com
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
SIERRA CLUB	
LEAH BAHRAMIPOUR **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 leah.bahramipour@sierraclub.org	ROSE MONAHAN **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301-4096 stephanie.andrus@doj.state.or.us	
VITESSE LLC	
DENNIS BARTLETT **(C)** META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 dbart@meta.com	IRION SANGER **(C)** **(HC)** SANGER LAW PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com
JONI L SLIGER **(C)** **(HC)** SANGER LAW PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 joni@sanger-law.com	

Dated this 1st day of September, 2023.

*/s/ Suzanne Prinsen*__________
Legal Assistant
McDowell Rackner Gibson PC

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 420

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, 2024 Transition Adjustment Mechanism.	**PACIFICORP'S EXHIBIT LIST AND CROSS-EXAMINATION EXHIBITS**

PREFILED EXHIBITS

Ramon J. Mitchell, Manager, Net Power Costs	
PAC/100	Direct Testimony of Ramon J. Mitchell
PAC/101	Oregon-Allocated Net Power Costs
PAC/102	Net Power Costs Report
PAC/103	Update to Renewable Energy Production Tax Credits
PAC/104	Net Power Costs Step Log
PAC/105	February 28, 2023 Notice Letter
PAC/106	2019 Benchmark Report
PAC/400	Reply Testimony of Ramon J. Mitchell
PAC/401	Step Log Changes
PAC/402	Oregon-Allocated Net Power Costs
PAC/403	Net Power Costs Report
PAC/404	Modeling Refinements and Sensitivities
PAC/800	Surrebuttal Testimony of Ramon J. Mitchell
James Owen, Vice President of Environmental, Fuels, and Mining	
PAC/200	Direct Testimony of James Owen
PAC/201	Hunter/Gentry CSA Analysis
PAC/202	Dave Johnston CSA Analysis
PAC/203	Wyodak CSA Analysis
PAC/204	Hunter/Bronco CSA Analysis
PAC/205	CSA Contract Minimums Table
PAC/500	Reply Testimony of James Owen
PAC/501	Hunter/Wolverine Coal Supply Agreement Analysis
PAC/502	Jim Bridger Plant Long-Term Fueling Plan
PAC/900	Surrebuttal Testimony of James Owen
PAC/901	Excerpts from the Huntington/Wolverine CSA
PAC/902	Corrected 2023 Jim Bridger Long-Term Fuel Supply Plan

Judith M. Ridenour, Specialist, Pricing and Cost of Service	
PAC/300	Direct Testimony of Judith M. Ridenour
PAC/301	Proposed TAM Rate Spread and Rates
PAC/302	Proposed Tariff Schedule
PAC/303	Estimated Effect of Proposed TAM Price Change
Zepure Shahumyan, Director of Energy and Environmental Policy	
PAC/600	Reply Testimony of Zepure Shahumyan
Matthew D. McVee, Vice President, Regulatory Policy and Operations	
PAC/700	Reply Testimony of Matthew D. McVee
PAC/1000	Surrebuttal Testimony of Matthew D. McVee
Ryan Fuller, Senior Tax Director	
PAC/1100	Surrebuttal Testimony of Ryan Fuller
PAC/1101	Example 2024 PTC Rate Calculations
PAC/1102	Quick Guide: Some Popular BEA Price Indexes
PAC/1103	Projections of the 2023 GDP Implicit Price Deflator
PAC/1104	Congressional Budget Office 2023 GDP Price Index Forecast
Michael G. Wilding, Vice President of Energy Supply Management	
PAC/1200	Surrebuttal Testimony of Michael G. Wilding
PAC/1201	Vitesse Data Request 25

CROSS-EXAMINATION EXHIBITS

Exhibit PAC/1300	Docket No. UE 390 Order No. 21-379 (redacted version)
Exhibit PAC/1301	Docket No. UE 390 AWEC/100 Opening Testimony of Bradley G. Mullins
Exhibit PAC/1302	Docket No. UE 390 AWEC/200 Rebuttal and Cross-Answering Testimony of Bradley G. Mullins (redacted version)
Exhibit PAC/1303	Docket No. UE 400 AWEC/100 Opening Testimony of Bradley G. Mullins
Exhibit PAC/1304	Docket No. UE 416 AWEC/100 Opening Net Variable Power Cost Testimony of Bradley G. Mullins
Exhibit PAC/1305	Docket No. UE 420 AWEC Discovery Responses to PacifiCorp
Exhibit PAC/1306	Docket No. UE 296 ICNU/200 Cross-Answering Testimony of Bradley G. Mullins (redacted version)
Exhibit PAC/1307	Docket No. UE 323 Excerpt of August 31, 2017 Hearing Transcript
Exhibit PAC/1308	Consumer Price Indices 2023

Exhibit PAC/1309	Federal Open Market Committee Projections June 14, 2023
Exhibit PAC/1310	Docket No. UE 420 Staff Discovery Responses to PacifiCorp (Highly Confidential and Confidential)
Exhibit PAC/1311	Docket No. UE 307 Order No. 16-482
Exhibit PAC/1312	Docket No. UE 390 Staff/700 Opening Testimony of Rose Anderson (redacted version)
Exhibit PAC/1313	Docket No. UE 207 Order No. 09-432
Exhibit PAC/1314	Docket No. UE 296 Order No. 15-394
Exhibit PAC/1315	Docket UE 421 Staff/100 Opening Testimony of Curtis Dlouhy, Julie Jent, Anna Kim, and Rose Pileggi

Respectfully submitted this 1st day of September 2023.

Katherine McDowell
Adam Lowney
McDowell Rackner Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
Phone: (503) 595-3922
Email: katherine@mrg-law.com
adam@mrg-law.com

Ajay Kumar
Assistant General Counsel, PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Phone: (503) 813-5161
Email: ajay.kumar@pacificorp.com

Attorneys for PacifiCorp dba Pacific Power

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1300

Docket No. UE 390
Order No. 21-379 (redacted version)

September 1, 2023

ORDER NO. 21-379

ENTERED Nov 1, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism.	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENTS

I. SUMMARY

The purpose of the Transition Adjustment Mechanism (TAM) proceeding is to annually update net power costs (NPC) and to set transition adjustments for Oregon customers who choose direct access in the November open enrollment window. The rates will become effective on January 1, 2022. In this order, we decide the contested issues for PacifiCorp, dba Pacific Power's 2022 TAM. We adopt a $3.4 million reduction to PacifiCorp's market cap proposal[1] and a $1.09 million reduction to account for nodal pricing model operational benefits.[2] Together these two adjustments reduce PacifiCorp's requested NPC amount by $4.49 million Oregon-allocated or approximately 1.5 percent. We also direct PacifiCorp to provide additional information that we find is necessary in future TAMs to facilitate parties' review of new Coal Supply Agreements (CSAs) and to evaluate PacifiCorp's management of established CSAs.

II. BACKGROUND AND PROCEDURAL HISTORY

In this case, PacifiCorp proposed a $1.1 million estimated increase in Oregon-allocated NPC for calendar year 2022.[3] The rate increase reflects higher Oregon loads when compared to the 2021 forecast loads, increased power purchases, and increased wheeling expenses, offset by decreased coal fuel expense. Other significant line items in the 2022 TAM are an increase in Energy Imbalance Market (EIM) benefits and $68.4 million in Production Tax Credit (PTC) benefits (Oregon-allocated).[4]

[1] Staff/800, Dlouhy/24.
[2] Staff/900, Gibbens/12.
[3] PacifiCorp Opening Brief at 1, n 1 ("This amount reflects the $1.7 million increase in the TAM reply update, less a correction for the WAPA firm transmission costs of $609,086.").
[4] PacifiCorp Opening Brief at 1.

Following the intervention by the Alliance of Western Energy Consumers (AWEC), Calpine Solutions, Oregon Citizens' Utility Board (CUB), Small Business Utility Advocates (SBUA), and Sierra Club, the five parties and Staff filed opening testimony and exhibits on June 9, 2021. PacifiCorp filed its updates and corrections to the NPC and reply testimony and exhibits on July 9, 2021. In its update, PacifiCorp accepted three adjustments proposed by the parties: (1) Staff's proposal to improve EIM benefits modeling, (2) certain Staff adjustments to the modeling of greenhouse gas (GHG) benefits, and (3) AWEC's adjustment to the PTC rate.[5] Those adjustments, combined with other GRID updates, offset each other, and PacifiCorp's requested Oregon-allocated NPC remains approximately $301 million, Oregon-allocated, and a proposed TAM rate increase of $1.1 million.

A hearing in this docket was held on August 26, 2021. PacifiCorp filed an opening brief on September 15, 2021, Staff and parties filed reply briefs on September 28, 2021, and cross-answering briefs on October 5, 2021. PacifiCorp filed its rebuttal brief on October 5, 2021.

PacifiCorp uses an on-going TAM general protective order[6] to govern the exchange of information designated as protected. For this proceeding, PacifiCorp also established a modified protective order[7] to govern the exchange of information designated as highly protected.

III. DISCUSSION

A. Applicable Standard

In the TAM, PacifiCorp retains the burden of proof to demonstrate that its proposed rate or schedule of rates is fair, just, and reasonable.[8] We must base our decision in a contested case on the evidence in the record in the proceeding. As the parties note, we have previously explained: "[t]he 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

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[5] PAC/400, Staples/5-6.
[6] *In the Matter of PacifiCorp 2017 Transition Adjustment Mechanism,* Docket No. UE 307, Order No. 16-128 (Mar 28, 2016).
[7] Order No. 21-086 (Mar 23, 2021).
[8] *In the Matter of Portland General Electric Co. Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-777 (Aug 31, 2001).

goal, therefore, is to achieve an accurate forecast of PacifiCorp's power costs for the upcoming year."[9]

B. Coal Issues

1. Requests for Forward-Looking Directives on Coal Issues

a. Filing Requirements for Future TAMs

(1) Overview

Sierra Club, Staff, and CUB raise concerns about the lack of transparency into PacifiCorp's CSA negotiations. To address their concerns, the parties recommend that PacifiCorp be required to file copies of all CSAs and affiliate mine plans in future TAM filings, and that PacifiCorp provide information on economic cycling, coal consumption forecasts, and workpapers.

(2) Parties' Positions

Sierra Club, Staff, and CUB recommend that PacifiCorp be required to provide copies of its coal supply agreements and affiliate mine plans in each TAM filing. The parties state ready access to this information is necessary given that the contracts and mine plans represent a substantial portion of NPC. Staff and Sierra Club describe difficulties with the current discovery approach, which limits access to coal contracts and affiliate mine plans to viewing in person or over a web platform. This limited access does not allow parties enough time to fully review and analyze contract provisions.[10] Staff recommends that PacifiCorp file copies of its CSAs and affiliate mine plans in each TAM, subject to proper handling under a modified protective order. Alternatively, at a minimum, Staff recommends PacifiCorp should be required to provide copies of all new CSA and mine plans in the TAM following execution of the document.

Staff requests the filing directive include three sub-components for additional information. First, for every new CSA subject to review, PacifiCorp provides a detailed explanation of how economic cycling was considered when deciding on minimum take levels in the contract. EIM participation should not exclude plants from economic cycling and PacifiCorp should show whether EIM participation is better for customers than economic cycling. Joint ownership should not exclude plants from economic cycling and PacifiCorp should show whether cycling would be economic. If it is economic, then PacifiCorp should reach out to the co-owner to request they consider

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[9] *In the Matter of PacifiCorp 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 4 (Dec 20, 2016).
[10] Staff Reply Brief at 18; Sierra Club Reply Brief at 28.

cycling. Second, PacifiCorp should include a chart comparing MMBtus from the generation forecast used to inform contract negotiations to the MMBtus in the contract. Third, PacifiCorp should include workpapers for the generation forecasts used to inform negotiations for new CSAs.

(3) PacifiCorp's Response

PacifiCorp responds to parties' requests for filing CSAs by stating that the modified protective order allows parties to seek copies of relevant sections of any CSA for use in developing their testimony, and that no party used this provision to request copies of CSA provisions. PacifiCorp explains it does not file CSAs with the Commission or provide full and unredacted copies to parties because its CSAs are extremely commercially sensitive, and PacifiCorp is contractually bound to maintain the confidentiality of the agreements.

PacifiCorp agrees to Staff's requests to include in future TAM filings information related to new CSAs, including an explanation of how economic cycling was considered, a comparison of forecasted generation to minimum take levels, and workpapers used to inform the range of generation used in negotiations.[11]

(4) Resolution

The CSAs and mine plans impact customer costs and PacifiCorp's TAM dispatch enough that regulators and parties need sufficient access to the documents to conduct a thorough review. In practical terms, we imagine that parties require time to think through contract terms, flexibility to discuss with coworkers with subject matter expertise, and the ability to conduct research into other similar agreements, as this is the type of regulatory review Commission employees engage in for any contested agreement. The amount and type of work required is not compatible with in person or screen sharing review.

We stop just short of requiring new CSAs and updated mine plans to be filed with the TAM as a default. It is possible there may be a solution that is in-between the current limited screen sharing review and the full copy filing requirement that PacifiCorp opposes. Because we do not currently have any CSAs filed in the record, we are not certain exactly how much time and access is necessary beyond the current level. We will require that PacifiCorp allow qualified persons to have more access to the CSAs and mine plans than was provided in this TAM, but we leave it to the parties to determine the exact mechanics. The modified protective order is entirely customizable, and parties may want to consider whether it may be tailored next year to more effectively meet their needs

[11] PacifiCorp Rebuttal Brief at 45-46.

for access, while ensuring there are limited copies of the CSAs and mine plans circulating.

We support the parties' agreement for PacifiCorp to provide additional explanatory materials to support future CSA review. More explanation and description is helpful for determining whether a contract is reasonable. PacifiCorp has agreed to Staff's request for a detailed explanation of how economic cycling factored into analysis for a minimum take level, a comparison of the MMBtu level from generation analysis to the contracted-for level, and to provide the workpapers used in analysis of generation forecasts for CSA negotiations.

b. Future CSAs: Required Analysis and Best Practices Guidelines

(1) Parties' Positions

CUB requests Commission guidance on a process for examining the viability of coal units with questionable economics in future proceedings. CUB cites Jim Bridger as an example of how IRPs reveal benefits from early closure, but do not give direction as to how the plant should operate during the interim period until it is closed or converted to gas. CUB asserts that intervenors should be able to examine choices, such as whether the plant should operate seasonally or be completely shut down in the TAM. CUB asks the Commission to establish a process that includes various model runs in the TAM, examining various closure dates once a resource's economics approach the uneconomic threshold.[12]

Sierra Club states that PacifiCorp's coal contracts do not merely play an important role in dispatch decisions, they dictate how the coal fleet operates.[13] Sierra Club recommends we adopt best practices for future CSAs that can be used to assess the agreements. Sierra Club provides five possible standards. First, analyze average or full cost modeling, a variety of demand scenarios, and economic cycling to ensure the reasonableness of minimum take provisions. Sierra Club states that modeling coal plant dispatch using the average cost would illustrate the most likely quantity of economically dispatched coal while considering the full set of costs associated with that coal burn. Second, minimum take requirements should be 50 percent of projected coal burn or less, to maximize flexibility. Third, require contract terms that allow the minimum take to be adjusted under changing regulatory and economic conditions. Fourth, minimize the length of coal contracts. Fifth, require that PacifiCorp produce evidence in future TAMs showing it incorporated these best practices before executing each new coal contract.

[12] CUB Reply Brief at 11.
[13] Sierra Club's Reply Brief at 22.

(2) PacifiCorp's Response

PacifiCorp responds that CUB's request will effectively convert the TAM into a resource planning docket akin to an IRP, which is improper.[14]

In response to Sierra Club, PacifiCorp states its coal procurement strategy ensures system reliability with a reliable fuel supply. PacifiCorp maintains that minimum take obligations are PacifiCorp's commitment to the coal producer that coal will be purchased, assuring the producer to invest sufficient capital in the mine to provide a reliable supply. Coal mines cannot ramp up supply overnight to respond to increased demand from low hydro conditions or high natural gas prices, and executing CSAs with reasonable minimum take provisions better ensures the coal will be available when needed.

PacifiCorp responds to Sierra Club's suggested CSA best practices. First, PacifiCorp states that it already forecasts generation using the plant's average costs, has incorporated cycling consistent with the modeling used in the TAM and agrees to continue to do so, and agrees to model multiple demand scenarios, as it did with Hunter. Second, PacifiCorp opposes Sierra Club's suggestion for a 50 percent threshold as unsupported. Third, PacifiCorp states it will pursue risk mitigation clauses in its CSAs that allow it to reduce or avoid its minimum take obligations, but opposes a requirement for those contract terms because counterparties are generally unwilling to contract away the certainty provided by a minimum take provision without receiving other assurances, such as a longer contract term or a much higher price.[15] Fourth, PacifiCorp's approach to CSA duration is to limit the period to five years or less to maintain flexibility in fuel and generation planning.[16]

(3) Resolution

In our finding above, we concluded that regulators and parties must have access to CSAs and mine plans with confidentiality protections, and that in a TAM where a CSA or mine plan is being reviewed, PacifiCorp must include a detailed explanation of how economic cycling was considered, a comparison of the MMBtu level in the generation analysis versus the contract level, and workpapers used for the generation analysis. As stated above, this information is helpful to parties' and the Commission's review of the reasonableness of PacifiCorp's actions. In this section we consider what types of analyses should be conducted in the situation where a plant is nearing retirement or when a minimum take level is likely to be disputed. We set out general expectations but do not create any pre-determined guidelines.

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[14] PacifiCorp Rebuttal Brief at 44.
[15] PacifiCorp Rebuttal Brief at 28.
[16] PAC/200, Ralston/3.

When a CSA extends to a unit's retirement date, we expect PacifiCorp to explain how it incorporates its IRP planning into its TAM-reviewed fuel contracts, or its management of those contracts. When we review a CSA, we will need to understand how PacifiCorp 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. 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. We do not require an extra plan or report, and expect the parties will raise different concerns with different units in each TAM, but ultimately, we expect that PacifiCorp will explain its general plan and why it is reasonable for customers.

We do not impose specific guidelines on our future CSA review, yet we emphasize to PacifiCorp that the Commission's review of utility actions for prudence involves, in part, a review of the processes and analyses used by the utility in its decision-making process.[17] The higher the cost and larger the delivery, the more important it is that PacifiCorp shows it has followed a robust decision-making and contingency-planning process, where it considers the benefits and costs of utilizing a short term, a conservative delivery amount, and seeking flexibility within contracts.

2. Coal Supply Agreements Driving Dispatch of Coal Plants

Stakeholders raise concerns that coal contract minimum take provisions are driving coal dispatch.[18] Several coal plants are operating close to their minimum take levels. PacifiCorp ensures these plants' generation levels are not below the contract minimums set forth in the TAM forecast or in actual operations by dispatching the units as if they have no fuel costs up to the contract minimum.[19] Parties argue that GRID is not producing the most economic generation forecast because PacifiCorp imposes pricing manipulations and other constraints.[20]

[17] *See In the Matter of PacifiCorp Request for a General Rate* Revision, Docket No. UE 246, Order No. 12-493 at 26-27 (Dec 20, 2012).
[18] CUB/100, Jenks/9 (Errata).
[19] CUB/105, Jenks/2 (citing PacifiCorp's response to Sierra Club Data Request 1.5 "For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1 million tons. The incremental price for volumes between zero and 1 million tons would be zero because the take-or-pay volumes are treated as a previously incurred cost.").
[20] Sierra Club Reply Brief at 3.

a. Economic Cycling

(1) Overview

When a coal plant economically cycles in the TAM forecast or in actual operations, it is turned off for a period of time when it is uneconomic. In last year's TAM, the parties agreed that PacifiCorp would not use must run requirements which limit the ability of GRID to economically cycle plants. In this TAM, PacifiCorp included a confidential study allowing coal plants to economically cycle.[21]

(2) Parties' Positions

CUB states the economic cycling study raises concerns about the operations of Jim Bridger. CUB explains that the IRP also suggested Jim Bridger dispatch is uneconomic, as the coal studies associated with the IRP found benefits from retirement of Jim Bridger 1 in [redacted] 2023. CUB is not convinced by PacifiCorp's assertion that Jim Bridger should remain online, albeit at its minimum, because of reliability concerns and the delay involved in bringing a unit back online. CUB suggests that a Bridger unit should be able to temporarily cycle down in 2022 and 2023, until December 2023, at which time the unit can be completely shut down or converted to natural gas.

CUB, Staff, and Sierra Club recommend that PacifiCorp conduct a GRID study that closes Jim Bridger 1 for the [redacted][22] CUB believes the Commission would benefit from seeing how GRID models the unit when given the freedom to economically cycle the unit generally and from seeing whether there are economic benefits from [redacted][23] Staff recommends that the study include practical considerations, such as whether the unit can be cycled off while still allowing necessary maintenance to take place on other units.

Staff notes that, alternatively, an economic cycling study that would identify economic cycling opportunities across PacifiCorp's system could negate the need to review Jim Bridger Unit 1 individually. Staff explains that PacifiCorp's economic cycling study in this TAM resulted in a large volume of "emergency purchases" and that the modeling can be improved to show economic cycling in a way that meets the requirements of a reliable generation plan. Staff suggests reducing the number of coal units that are allowed to cycle off at a given time, by looking for available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, or by

[21] PAC/107, Webb/3.
[22] CUB Reply Brief at 4; Sierra Club Reply Brief at 34.
[23] CUB/200, Jenks/13.

utilizing a new model that is able to consider reliability in its economic cycling decisions.[24]

CUB and Staff also ask us to require that PacifiCorp allow GRID to economically cycle Jim Bridger 1 in its TAM forecasts. This recommendation is subject to PacifiCorp's analysis, determining that economic cycling of Jim Bridger Unit 1 is beneficial to customers, while meeting reliability requirements and ensuring an appropriate maintenance schedule is maintained.

(3) PacifiCorp's Response

PacifiCorp responds that the parties' request to enable Jim Bridger Unit 1 to cycle in the TAM has already been met. PacifiCorp states that, in the 2022 TAM, PacifiCorp removed the "must run" setting for all coal units, including Jim Bridger Unit 1 and PacifiCorp intends to continue doing so in future TAMs.

PacifiCorp responds to the parties' second request for a study of Jim Bridger Unit 1 turned off for the [redacted] by stating there is no reason for the Commission to order a study when each party to the TAM can request such a study and PacifiCorp will provide a single model run based on whatever assumptions the party requests. To the extent that Staff, CUB, or Sierra Club want the company to run Aurora in the 2023 TAM, with the assumption that Unit 1 is cycled off for the [redacted], they can make that request.[25]

(4) Resolution

We direct PacifiCorp to complete a follow-up economic cycling study as Staff requests. We decline to require the specific study that CUB requests because of the potential redundancy between a fleet-wide follow-up cycling study and CUB's targeted study. In the event CUB's question regarding Jim Bridger's economics is not answered in the fleet-wide follow-up cycling study, then CUB may request the model be run specifically following the terms of the 2021 TAM stipulation.

The overall question that PacifiCorp's follow-up economic cycling study should address is whether economic cycling of units, with reliability considerations factored in, creates savings for customers.[26] We recognize that an economic cycling study may not be dispositive in defining the precise levels at which a plant is reasonably operated (given operational realities and economic considerations regarding the structure of the contracts related to fuel supply) but find that such a study is nevertheless highly likely to be

[24] Staff/700, Anderson/6.
[25] PacifiCorp Rebuttal Brief at 43.
[26] Staff/700, Anderson/5.

beneficial in parties' and our review. This analysis may help inform parties' evaluation of new CSAs and PacifiCorp's management of existing contracts. We find the follow-up study should be informative, and do not go so far as to require PacifiCorp to include specific cycling benefits from the study into its 2023 TAM forecast. PacifiCorp retains discretion to present an accurate and reasonable TAM forecast, and we will of course allow all parties to present, in future relevant proceedings, their views on the implications of the study for cost recovery.

PacifiCorp has indicated that its Aurora model may be capable of considering reliability while identifying which coal units to cycle, which would remedy Staff's main complaint with the cycling study in this TAM. PacifiCorp, Staff, and stakeholders should communicate about the parameters of the follow-up study during Aurora workshops, and PacifiCorp should file the follow-up study with the 2023 TAM.

b. Modeling of Minimum Take Levels

(1) Overview

PacifiCorp uses a "dispatch tier" for coal fuel pricing in GRID. The dispatch tier price is based on the unit's incremental cost, or the cost to produce one additional MWh of energy. PacifiCorp excludes the costs of coal subject to take or pay provisions, because such costs are previously incurred and classified with the fixed costs. PacifiCorp uses the dispatch tier pricing in GRID to determine dispatch. PacifiCorp uses a separate "costing tier" that includes the fixed costs and represents the unit's average costs to calculate the NPC charged to customers.[27]

Sierra Club argues that two of PacifiCorp's modeling practices unreasonably favor coal at the expense of lower cost resources. First, Sierra Club asserts that PacifiCorp's incremental pricing in its "dispatch tier" improperly excludes certain fixed costs, and that PacifiCorp should use accurate incremental pricing for its coal fleet in future modeling. Second, Sierra Club has concerns with PacifiCorp's iterative GRID runs that force the model to project minimum quantities of coal burn and recommends that we require PacifiCorp to disclose the dispatch tier adjustments made in order to meet minimum take requirements.

(2) Parties' Positions

Sierra Club argues that PacifiCorp removes certain costs as fixed that should be treated as variable. By reducing the incremental dispatch tier pricing GRID results assume a plant is significantly less expensive than is accurate. Sierra Club provides four scenarios when

[27] Sierra Club Reply Brief at 4-5.

minimum take requirements are not yet a sunk cost for ratepayers and at least a portion of the coal supply is a variable cost that should be included in the dispatch tier cost. First, PacifiCorp assumes it is bound by minimum take requirements before the contract is approved, such as at Hunter, Dave Johnston, and Craig (discussed below). Second, PacifiCorp assumes obligations when the contracts have not yet been signed for 2022. For example, the assumption that PacifiCorp will have a minimum take with Black Butte for Jim Bridger when that contract has not yet been signed. Sierra Club's last two scenarios are when there is no minimum take requirement, or the minimum take requirement can be avoided under the contract. Sierra Club recommends that we direct PacifiCorp to include all variable coal costs in future modeling, without premature assumptions that ratepayers will be bound by minimum take requirements.

Sierra Club argues PacifiCorp further manipulates its coal plants' pricing through an iterative process, whereby PacifiCorp manually reduces the incremental price until the minimum take requirement is met. In this proceeding, a manual adjustment was made for Huntington, Colstrip, and Hayden. Sierra Club states that PacifiCorp's iterative process is an indication that minimum take requirements are driving uneconomic coal consumption and it is critical that the Commission be aware of when adjustments to a plant's dispatch tier are made and to what degree. Sierra Club explains that PacifiCorp's witness conceded that manual adjustments year-over-year would indicate uneconomic generation.[28] Sierra Club recommends the Commission require PacifiCorp to file in future TAM proceedings the initial incremental price for each coal plant, the final dispatch tier price, and the magnitude of the difference with historical information for the past five years. Sierra Club states that PacifiCorp is already required to provide similar information to the California Public Utilities Commission.[29]

(3) PacifiCorp's Response

PacifiCorp responds that it adjusts the dispatch price for a coal plant only if doing so is necessary to cover a minimum take obligation, which undoubtedly reduces overall customer costs.[30] PacifiCorp states that Sierra Club is incorrect in suggesting that it manipulated the dispatch tier price for plants with new CSAs or open positions in 2022, because those plants did not require any modification to the dispatch tier price in order to meet a minimum take obligation.

[28] Sierra Club Reply Brief at 9 (citing Hearing Transcript at 106:6-11 (Ralston, PacifiCorp) "Q. What, within the TAM, would signal uneconomic production? A. If there was multiple years that we had to force the burns to make the minimum requirement, not just one year, but let's just say the last several years, that would be uneconomic.").
[29] Sierra Club Reply Brief at 10.
[30] PacifiCorp Rebuttal Brief at 23-24.

(4) Resolution

We will require PacifiCorp to provide the information requested by parties but do not direct PacifiCorp to change its specific modeling inputs. These findings are consistent with our conclusions above, that parties (and regulators) should be able to see contracts, analysis, and modeling information that will provide insights that will be helpful in reviewing whether a new CSA is reasonable or whether PacifiCorp is appropriately managing an existing CSA.

As to Sierra Club's specific argument on PacifiCorp's manual adjustments to dispatch pricing, we do not find that PacifiCorp acted unreasonably by accounting for minimum take levels in its modeling of resource operation. However, we agree with Sierra Club's point that the spread between the initial incremental price and the final dispatch tier price is possibly the strongest indicator in the TAM that a plant may be dispatching more than is economically optimal, and that a multiyear period in which that spread is significant should prompt PacifiCorp to consider its options for management of the contract (*i.e.*, to evaluate costs and benefits of alternatives). Rather than require PacifiCorp to report five years of data, we require four years, so that the 2023 TAM should include past pricing from the 2020 TAM forward. Four years is consistent with other TAM modeling such as the market caps that are disputed in this proceeding. We also direct PacifiCorp to include the costing tier for each plant for each year, and the differential between the initial incremental price and the costing tier price so parties can consider the variations in the incremental price discount from plant to plant.

c. Forecasted Generation at Jim Bridger

(1) Overview

Pricing for the Jim Bridger coal supply falls into three tiers: the Black Butte price, the BCC "base" price (which is tied to assumed generation levels at the Bridger Coal Company mine), and the BCC "supplemental" price (which represents coal available to PacifiCorp once the base quantity has been purchased). Sierra Club argues that PacifiCorp has improperly lowered the dispatch tier to [redacted] than actual cost in the costing tier, resulting in GRID assuming Jim Bridger is significantly less expensive than is accurate.[31]

[31] Sierra Club Reply Brief at 5, 12.

(2) Parties' Positions

Sierra Club explains that Jim Bridger is one of PacifiCorp's most expensive coal plants, yet GRID continues to forecast relatively high generation because PacifiCorp lowers the dispatch tier price by using the BCC supplemental coal price for the dispatch tier. Sierra Club asserts that the BCC coal supply has no genuine minimum take requirement. Therefore, it is improper for PacifiCorp to treat the BCC base quantity of coal from the mine as though it were a minimum take requirement and exclude the cost from the incremental price dispatch tier.

Sierra Club states that PacifiCorp determines the amount of coal BCC produces and has discretion to reduce production. Sierra Club explains that PacifiCorp annually develops a BCC mine plan that establishes anticipated coal production, and that PacifiCorp has not evaluated any production levels below the current base plan. Sierra Club concludes that because PacifiCorp is not subject to a minimum take requirement at Black Butte and the majority of BCC costs are variable, the BCC supplemental price tier is not an appropriate incremental price point for the Jim Bridger plant. Sierra Club asserts that the Jim Bridger dispatch tier should more closely resemble the BCC base price. Using a GRID run that approximated this price with the average price (which is lower than the BCC base price) Jim Bridger consumers [redacted] MMBtus, compared to over [redacted] in PacifiCorp's TAM application. Based on these fuel savings, Sierra Club recommends we disallow [redacted] on an Oregon-allocated basis associated with excessive forecasted generation at Jim Bridger.[32]

(3) PacifiCorp's Response

PacifiCorp states that it dispatches the Jim Bridger plant based on the incremental cost to generate additional energy, which for Jim Bridger is the supplemental cost for BCC coal. PacifiCorp determines the incremental (*i.e.*, supplemental) cost based on the cost differential between two mine plans with different production volumes. PacifiCorp asserts this methodology isolates the fixed costs of the BCC mine that are incurred regardless of production levels.[33] PacifiCorp explains that it uses average costs in the IRP modeling for long-term resource decisions. In contrast, the TAM is a short-term forecast therefore, PacifiCorp maintains that it appropriately makes dispatch decisions using short-run incremental costs. PacifiCorp refutes Sierra Club's calculation on Jim Bridger fuel savings and states that when Black Butte costs are added to the BCC fixed costs, there is little cost savings from using average price dispatch.[34]

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[32] Sierra Club Reply Brief at 20.
[33] PacifiCorp Rebuttal Brief at 29.
[34] PacifiCorp Rebuttal Brief at 35.

(4) Resolution

Jim Bridger costs, as translated into modeling inputs and shown in the TAM forecast, merit additional attention both because of their magnitude and because of PacifiCorp's flexibility to alter BCC deliveries. As we have in past TAMs,[35] we again require PacifiCorp to update and file the Jim Bridger Long Term Fuel Plan document in the 2023 TAM. Having studied this fuel plan twice before, we add feedback for PacifiCorp to use in designing the bookends that it studies in the fuel plan.

An updated mine plan should explicitly reflect the changing future of Jim Bridger. We have not lost sight of the realities of somewhat inelastic production levels at a mine, but we encourage PacifiCorp to look at scenarios that may involve even significant change in its management of the resources, such as, for example, the consequences of fueling Jim Bridger solely from BCC or solely from Black Butte. Because of the large size of Jim Bridger, we have some concerns about a pre-set BCC production level or Black Butte delivery that could get in the way of portfolio changes already promised in planning and procurement dockets as new renewables come online. We ask PacifiCorp to ensure that the Jim Bridger fuel plan allows Jim Bridger to decrease output as new generation comes online, a rather drastic dispatch trend forecasted in the RFP.[36]

In response to Sierra Club's arguments about the low cost of BCC supplemental coal driving Jim Bridger's dispatch, we find that it seems reasonable for PacifiCorp to at least be informed by an average cost analysis that may present a different view than the traditional TAM modeling of how the long-term fuel plan could optimize a new Black Butte CSA, the shutdown or conversion of the units, and the level of production at the units by considering the full cost of coal. Again, our finding about what evaluation should take place ahead of new CSAs does not affect our acceptance of PacifiCorp's traditional modeling of a CSA once the CSA is in place and found reasonable.

[35] *In the Matter of PacifiCorp, 2018 Transition Adjustment Mechanism,* Docket No. UE 323, Order No. 17-444 (Nov 1, 2017) ("We also approve PacifiCorp's plan to finalize an updated long-term Jim Bridger fuel plan, which should be filed both in this docket and as an attachment to initial testimony in the 2019 TAM. Jim Bridger coal costs continue to be significant and will require on-going monitoring."); *In the Matter of PacifiCorp, 2019 Transition Adjustment Mechanism*, Docket No. UE339, Order No. 18-421 (Oct 26, 2018) (adopting the parties' agreement to update the plan to shorten the life of Jim Bridger post SB 1547).

[36] Official notice per OAR 860-001-0460 is taken of PacifiCorp's Response to ALJ Bench Request 5 in Docket No. UM 2059 (Aug 17, 2021) (showing a [redacted] in coal generation overall in IRP dispatch beginning in 2025 once the RFP renewable resources are added, and showing Jim Bridger's capacity factor of approximately [redacted] in the 2022 TAM falls to approximately [redacted] in 2025.).

d. Bridger Coal Company Costs

(1) Parties' Positions

AWEC states that PacifiCorp's materials and supplies expenses have been grossly overstated in every year analyzed. In 2020, for example, AWEC asserts the forecast was overstated by 32 percent.[37] AWEC recommends an adjustment based on the historical variances identified between the forecast amounts and the expenses actually incurred, with a $1,175,112 reduction to Oregon-allocated NPC.[38] AWEC maintains that whether PacifiCorp spends the money on coal production or reclamation activity, ratepayers see the costs as power costs, and therefore, the Bridger Coal Company materials and supplies costs should be accurately forecast.

(2) PacifiCorp's Response

PacifiCorp responds that AWEC and Staff propose an adjustment to decrease one line item embedded within BCC coal costs related to the materials and supplies expense. PacifiCorp maintains that overall BCC coal costs have been within 1 percent of the forecasted amount over the last five years. PacifiCorp states that the materials and supplies expense appeared overstated in the last three years because the expenses were incurred both for coal production and reclamation activities, and that reclamation activities were much higher in the last three years.[39]

(3) Resolution

We decline to make an adjustment on this issue. Doing so would require us to impose a downward adjustment based on one individual line-item that may decrease (based on past experience) while ignoring that past actual expenses show that the overall cost category within which that line item fits has been reasonably forecast. We understand AWEC's point that PacifiCorp's forecast levels are based on subjective judgements, and we ask PacifiCorp to include a discussion of these costs in its updated Jim Bridger long term fuel plan so that parties have the opportunity to review components as well as the whole of BCC costs.

[37] AWEC/100, Mullins/22.
[38] AWEC Reply Brief at 17.
[39] PacifiCorp Rebuttal Brief at 44.

3. ***Reasonableness of Coal Supply Agreements***

a. New Coal Supply Agreements – Hunter, Dave Johnston and Craig

(1) Overview

PacifiCorp has entered into five new CSAs: two related to Hunter, two related to Dave Johnston, and one related to Craig. CUB, Staff, and Sierra Club commented on the contracts. The three parties raise specific concerns with the new Hunter CSAs which are at the same delivery level as the previous, 20-year-old contract. Parties question why generation at Hunter is not declining when PacifiCorp has reduced coal generation by approximately 32 percent since 2018, both system-wide and at Hunter.[40] The CSAs for Dave Johnston and Craig are not specifically contested but are generally opposed by Staff and Sierra Club due to concerns that PacifiCorp's economic cycling analysis is insufficient to support minimum take levels in new contracts.

(2) Dave Johnston and Craig CSAs

(a) Background

For Dave Johnston, PacifiCorp executed two new CSAs for deliveries from two mines, Caballo and North Antelope Rochelle (NARM), both in the Powder River Basin. Both agreements are [redacted]. The Caballo mine will supply [redacted] and NARM will supply [redacted]. The two new agreements are take-or-pay agreements, although PacifiCorp has the option to [redacted]. Including the new and existing agreements for Dave Johnston, there are [redacted] under contract in 2021, approximately [redacted] of the total [redacted] 2022 TAM forecast.[41] Oregon has an exit date of December 2027 for Dave Johnston.

The new CSA for Craig is with the Trapper Mine for a five-year agreement replacing the previous 11-year agreement. The Trapper Mine is an affiliate captive mine owned by PacifiCorp along with two of the five other owners of the Craig plant. PacifiCorp's share of the mine is 29.14 percent. The agreement has a prescribed flexible annual tonnage nomination. PacifiCorp's share of the annual tonnage nomination has a range of [redacted] million tons.[42] Oregon has an exit date of December 2025 for Craig unit 1 and December 2026 for Craig unit 2.

[40] CUB/100, Jenks/12; CUB/102, Jenks/1.
[41] PAC/200, Ralston/4-5.
[42] PAC/200, Ralston/9-10.

(b) Parties' Positions

Staff and Sierra Club state that PacifiCorp did not allow Dave Johnston or Craig plants to economically cycle in the analysis that informed its negotiations on the new CSAs.[43] Staff explains that the generation forecast at each plant is dependent on economic cycling outcomes at all of the other plants. Staff asserts that a study that looks at economic cycling of the fleet as a whole is necessary to determine the optimal level of generation at the coal plants. Without it, Staff concludes that it is not possible to know whether the minimum take provisions agreed to by PacifiCorp are reasonable and prudent. Staff recommends PacifiCorp be required to model the five new CSAs without minimum take requirements in the TAM for the duration of the contract term.[44]

CUB explains the Dave Johnston contracts benefit from low and competitive pricing for Powder River Basin coal. CUB is comfortable with Dave Johnston's take-or-pay risk as the delivery level maintains an open position that is reasonable in light of Dave Johnson's low dispatch cost, which makes it unlikely to be economically cycled. CUB states the primary take-or-pay risk would be from a significant outage of the plant and could likely be managed with the open portion of the fueling strategy.[45]

(c) PacifiCorp's Response

PacifiCorp responds that: (1) economic cycling is rare in actual operations; (2) GRID over forecasts cycling opportunities; (3) PacifiCorp modeled economic cycling of its entire fleet in the economic cycling study based on 2021 TAM inputs and it showed [redacted]; (4) PacifiCorp's 2022 TAM also modeled economic cycling of the entire fleet and it showed [redacted]; (5) the generation forecasts used to inform the Hunter and Dave Johnston CSAs specifically modeled cycling of the studied plants; (6) the Craig forecast did not include cycling, but if it had the results would not have impacted the minimum take level; (7) PacifiCorp has flexibility to adjust the Craig minimum take level if needed; (8) the company's modeling, used to forecast generation for the new CSAs, conformed to the economic cycling modeling that Staff agreed was reasonable in prior TAMs and that the Commission approved to set customer rates; and (9) the average cost of these plants including these CSAs in the 2022 TAM ranges from $[redacted]/MWh (Dave Johnston) to $[redacted]/MWh (Hunter) to $[redacted]/MWh (Craig), all of which are below the overall coal fleet average price of $[redacted]/MWh and well below the average price of natural gas generation in the 2022 TAM of $[redacted]/MWh.[46]

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[43] Staff Reply Brief at 10; Sierra Club Reply Brief at 25.
[44] Staff Reply Brief at 11.
[45] CUB/100, Jenks/11.
[46] PacifiCorp Rebuttal Brief at 36.

(d) Resolution

We approve the Dave Johnston and Craig CSAs as reasonable. Both the Dave Johnston and Craig CSAs have elements that we believe are reasonable, including that each of them has many of the characteristics of being relatively low cost, having a short duration, providing for flexible delivery, or a reasonable open position in light of the plant's general dispatch level. We note that the new requirements for additional information and analysis, described above, in particular when the CSA is large, expensive, or likely contested, will be helpful to reviews of future CSAs.

(3) Hunter CSAs

(a) Background

PacifiCorp has two new CSAs for Hunter. One CSA with Bronco has a [redacted], [redacted]. The Bronco agreement has a minimum take requirement of [redacted] tons at [redacted] per ton. The second CSA is [redacted] The Wolverine agreement has a minimum take requirement of [redacted] tons at [redacted] per ton and second tier pricing of [redacted] per ton. These CSAs are replacing the previous long-term agreement (20 years).

(b) Parties' Positions

Staff's objection to the Hunter CSA is due to PacifiCorp's lack of a fleet-wide economic cycling analysis to inform coal contract negotiations, as discussed in the previous section. Sierra Club similarly challenges the analysis, stating that PacifiCorp only permitted Hunter Units 1 and 2 to cycle in the spring months and did not allow Unit 3 to cycle at all.[47]

Sierra Club also argues that the minimum take levels in the new contracts are high and put ratepayers at risk of uneconomic generation or paying minimum take penalties. Sierra Club explains that if actual burn is 20-30 percent lower than the current GRID forecast, PacifiCorp will either incur minimum take penalties or force the plant to operate uneconomically. Sierra Club asserts that such a deviation is not unreasonable as similar reduced burn levels have occurred at other PacifiCorp plants, as CUB noted.[48] Sierra Club believes this declining trend will continue for coal generation, and over the course of the contracts, the minimum take requirements are likely to make up more of the expected burn to the point where it is likely within the contracts' time frame that Hunter

[47] Sierra Club Reply Brief at 26.
[48] CUB/102, Jenks/1.

will not economically meet its minimum take obligations. Sierra Club states there is no evidence that PacifiCorp evaluated shorter term contracts and that the Hunter contracts do not have provisions that would allow PacifiCorp to reduce or avoid the minimum take requirements due to an inability to economically use the coal.[49]

CUB has concerns regarding the minimum take provisions in the Hunter contracts but does not recommend any adjustments to this TAM because much of the risk associated with the take-or-pay contracts will fall into the PCAM deadband.[50]

(c) PacifiCorp's Response

PacifiCorp responds that it is highly unlikely that generation at Hunter would unexpectedly drop by [redacted] percent. PacifiCorp states this would put PacifiCorp's expected burn at [redacted] tons which is far below any level of coal consumption at the plant since 2017.[51] PacifiCorp disputes Hunter's past consumption decrease that Sierra Club and CUB cite. PacifiCorp argues the evidence does not support Sierra Club's claim that the minimum take level is too high.

(d) Bench Request Response

The bench request asked for Hunter's historical coal consumption so it could be compared to the new contract levels. PacifiCorp provided a comprehensive table showing coal deliveries (total-plant) and coal consumption (ownership-allocated) since 2017. The bench request also asked for PacifiCorp's analysis of Hunter's future consumption so it could be compared to the new contract levels. PacifiCorp explained that it did a scenario analysis in 2020 before signing the contracts. PacifiCorp showed that for Hunter's "low" scenario the forecasted consumption is: 2021 - [redacted] tons, 2022 - [redacted] tons, 2023 - [redacted] tons.

(e) Resolution

We consider whether PacifiCorp acted reasonably when it executed the two new Hunter CSAs by determining whether PacifiCorp's actions, "based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed."[52] We consider not just the decision made by the utility, but also the decision-making process used to reach that decision.[53]

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[49] Sierra Club Reply Brief at 33.
[50] CUB/100, Jenks/12.
[51] PacifiCorp Rebuttal Brief at 41.
[52] *In the Matter of PacifiCorp Request for a General Rate* Revision, Docket No. UE 246, Order No. 12-493 at 25 (Dec 20, 2012).
[53] *Id. a*t 26.

We find that PacifiCorp's analysis supports a prudence determination for the first three years of the contracts, through 2023. Hunter's past consumption averaged [redacted] million tons per year for the last 5 years, supporting the new CSA's delivery level at [redacted] million tons as reasonable. However, PacifiCorp's analysis of future consumption data only supports a reasonableness finding through 2023 and is silent on a reasonable consumption level in 2024, which is the final year of the [redacted] tons. We will defer the determination for 2024 and PacifiCorp can present its evidence to support the reasonableness of the 2024 delivery in a future TAM.

b. *Old Coal Supply Agreements – Huntington*

(1) Overview

In last year's TAM order, we raised concerns about the Huntington CSA. We asked parties to review the Huntington CSA and explained "[w]e are concerned that, because of the minimum take level in the Huntington coal supply agreement, PacifiCorp may not be able to decrease output at Huntington in coming years when other lower-cost generation is available."[54] The Huntington CSA is a long-term agreement that stems from the Deer Creek Mine settlement.[55]

(2) Parties' Positions

CUB states that in 2015 it joined PacifiCorp in arguing that the Huntington CSA was prudent, based in large part on PacifiCorp's representations that the contract contained broad termination rights relating to environmental laws and regulations.[56] CUB states the current issue is not whether the contract was prudent in 2015, or whether environmental laws or regulations directly impact operations of the plant. Rather, the issue is whether new environmental laws in multiple states who have increased renewables have made burning coal at the minimum levels in the contract uneconomical.[57] CUB cites to studies

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[54] *In the Matter of PacifiCorp 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct 30, 2020).
[55] PAC/200, Ralston/12 (citing *In the Matter of PacifiCorp, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 (May 27, 2015)).
[56] CUB/100, Jenks 13-14 (citing Docket No. UM 1712, PAC/500, Crane/7 (Mar 19, 2015) ("Q. Parties are also concerned that the long-term CSA creates an incentive for the Company to continue to burn coal at Huntington when it would otherwise be uneconomic to do so and therefore limits the Company's future options. Please respond. A. Because the Company can exercise its termination rights if it becomes uneconomic to burn coal at Huntington, there is no incentive to continue burning coal when it is uneconomic to do so and the Company's options are not limited.")).
[57] CUB/100, Jenks 14 (citing Oregon SB 1547 that phases out coal plants and required 50 percent renewables, and that Washington and California have passed 100 percent clean electricity laws).

showing that increased renewables reduce wholesale market prices, and that PacifiCorp exists in a market that reflects the impact of environmental laws and regulations.

CUB states that to justify pursuing the termination clause, the benefits must outweigh the risks and that PacifiCorp must be able to demonstrate that uneconomic dispatch would not be occurring but for increased environmental regulations. CUB states the legal risks of terminating the contract and the cost risks of an increased coal price have to be weighed against the value of termination, which in this case is [redacted] but may increase in coming years.[58] CUB argues that PacifiCorp has a responsibility to manage the contract prudently, including the termination clause.[59] CUB recommends that PacifiCorp conduct an analysis to determine whether the Huntington CSA is leading to uneconomic dispatch of the plant, whether it is due to new environmental laws and regulations, and whether it is in customers' interest to invoke the contract termination provisions by weighing the value of termination against any risks.[60]

(3) PacifiCorp's Response

In response, PacifiCorp agreed to continue to monitor market and regulatory conditions to assess whether there is an opportunity to invoke the termination clause, but does not find those conditions exist at this time.

(4) Bench Request Response

PacifiCorp's bench request response provided historical modeling information for Huntington. PacifiCorp described whether adjustments were required in the initial 2019, 2020, or 2021 TAM filings to account for Huntington's minimum take requirement. PacifiCorp also provided Huntington's incremental price, dispatch tier prices, and costing tier prices from the 2017 TAM to the 2022 TAM. The data showed that PacifiCorp had to manually [redacted] to have the plant meet its minimum take obligation.

(5) Resolution

We note Staff's initial testimony that "PacifiCorp has to manually increase the dispatch level at Huntington so that the minimum take quantity of coal can be utilized. This indicated to Staff that the minimum take levels in the Huntington contract were not calibrated appropriately for the economic realities even a few years into the future."[61]

[58] CUB/200, Jenks/20-21.
[59] CUB/200, Jenks/18.
[60] CUB Reply Brief at 13.
[61] Staff/700, Anderson/21.

Staff went on to identify the magnitude of the manual adjustment in this TAM as [redacted] MWh,[62] meaning almost [redacted] of Huntington's 2022 output of [redacted] MWh had to be forced to dispatch in GRID.

At hearing, when asked what, within the TAM, would signal uneconomic production, PacifiCorp responded "if there was multiple years that we had to force the burns to make the minimum requirement, not just one year, but let's just say the last several years, that would be uneconomic."[63] The data in the bench request response shows that PacifiCorp has had to make manual adjustments in GRID for each of the last four years to account for Huntington's minimum take requirement. Although PacifiCorp did not have the detail to identify the MWh magnitude of the adjustment, the differential between the incremental price and the dispatch tier price is even larger in 2019, 2020, and 2021, than it is in this TAM, indicating similar or even greater amounts of coal burn that PacifiCorp had to coax into the TAM dispatch to meet the minimum take level.

Confidential Table 1.[64]

[redacted]

With this review we find that a portion of the Huntington minimum take delivery amount is not economic in today's energy market that is shaped by new environmental laws, even if the minimum take levels were structured in a way that PacifiCorp believed to be reasonable at the time the contract was entered into. Given how many years remain in

[62] Staff/700, Anderson/22-23 (citing Staff/702, Anderson/12, PacifiCorp's response to Staff DR 162).
[63] Transcript at 106 (Aug 26, 2021) (Ralston, PacifiCorp).
[64] PacifiCorp Response to ALJ Bench Request 5 (table listing the values).

this contract, with a term that runs to December 31, 2029,[65] the four-year trend of manual adjustments causes us significant concern. With the data we have beginning in 2017, Huntington's minimum take delivery amount appears economic in 2017 and 2018, but in 2019 lower cost generation in GRID would have been available, if PacifiCorp had the flexibility to pursue it.

In 2019 PacifiCorp began bringing on additional wind energy with repowered wind facilities, followed by approximately 1,500 MW of new wind resources in 2020 and 2021. In the rate case where we reviewed some of these costs, we considered multiple benefits including the zero fuel-cost energy that lowers NPC, renewable energy certificates (RECs) which can be sold in the market or used to comply with Oregon's renewable portfolio standard targets, and reduced carbon emissions from PacifiCorp's resource portfolio to mitigate risk associated with potential future state policies (which have since become a reality with Oregon's HB 2021, including early action options for emissions reductions).[66] We find that beginning in 2019 the energy market began to have noticeable price decreases as RPS requirements in the West increased and tax-incentives induced accelerated addition of new renewable resources. The recently approved 2021 RFP short list demonstrated this issue is highly likely to intensify through the 2020s. In that docket, PacifiCorp again pointed to the multiple benefits of building transmission by 2024 and adding significant generating resources, including zero fuel-cost energy that lowers the NPC and emissions reductions from the Utah coal plants specifically.

Circumstances have changed since our initial determination on this CSA, and because PacifiCorp cannot economically consume Huntington's entire [redacted]-million-ton minimum take amount in today's market, it needs to show that it is managing the contract in today's environment. Going forward, we agree with CUB that PacifiCorp needs to present analysis on the costs and benefits of pursuing Huntington's [redacted]. If PacifiCorp does not thoroughly explore the costs and benefits of contract termination or renegotiation, we would be willing to entertain an argument for a disallowance.

[65] PAC/200, Ralston/11.
[66] *In the Matter of PacifiCorp, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Dec 18, 2020).

C. Other Contested Issues

1. Market Caps

a. Introduction and Background

CUB explains that PacifiCorp's power plants serve load first, and excess generation is sold to market if the production cost of the generator is under the market price. The issue with GRID's modeling of sales to market (also referred to as off-system sales) is that GRID does not predict market demand or limit sales, so market caps are inserted to limit the volume of sales.[67]

The existing market caps are based on the maximum sales over the last four years. PacifiCorp seeks to base the market caps on the average sales over the last four years. The methodology provides four separate data points for each month and hub in high load hours, and for low load hours. The dispute is whether the market cap is the highest of the four data points or the average of the four. PacifiCorp explains the effect of a lower market cap is to reduce the market depth at each hub, which reduces market sales modeled in GRID, and increases NPC.[68]

The parties' arguments on market cap methodology involve three separate sets of precedent: a TAM order, a rate case order, and a PCAM order. The current market cap methodology (maximum of averages) was litigated and adopted in the 2013 TAM.[69] Parties state that the Commission approved the maximum of averages as the middle ground between the average of averages approach (PacifiCorp's position) and no market caps (Staff's position). The rate case is where PacifiCorp's overall NPC under-recovery was litigated in 2020. The rate case order states "PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery."[70] Lastly, recent Power Cost Adjustment Mechanism (PCAM) orders have a section which summarizes PacifiCorp's filing with "PacifiCorp states the main deviation in power costs was due to a decrease in wholesale sales revenues relative to the forecast, with the actual volume of wholesale sales 68 percent less than forecast."[71]

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[67] CUB/100, Jenks/2-3.
[68] PAC/100, Webb/12.
[69] *In the Matter of PacifiCorp 2013 Transition Adjustment Mechanism,* Docket No. UE 245, Order No 12-409 at 7 (Oct 29, 2012).
[70] *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 130 (Dec 18, 2020).
[71] *In the Matter of PacifiCorp 2019 Power Cost Adjustment Mechanism*, Docket No. UE 379, Order No. 20-489 (Dec 29, 2020).

Next year Aurora will include prices at load points across the region as a whole. Parties think Aurora should more accurately model both short-term sales and purchases. PacifiCorp indicates that the market cap adjustment may still be needed in Aurora.

b. Parties' Arguments

PacifiCorp proposes replacing the current maximum of averages market cap methodology with the average of averages approach. PacifiCorp states the average of averages approach to market caps uses the same basic methodology as the maximum of averages approach, with both relying on a rolling four-year average by month, by market, and by high and low load hours. PacifiCorp states the only difference is that the average of averages approach sets the cap at the historical average, while the maximum of averages approach sets the cap at the highest sales level reflected in the historical data.[72]

PacifiCorp explains the market cap change reduces off-system sales volume by approximately 16 percent (or 1.4 million MWh total-company) in this case and increases NPC by $5.1 million (Oregon-allocated).[73] PacifiCorp believes the market cap change is conservative and argues that even under average of averages market caps, it is likely to continue to forecast more off-system sales than it can achieve in actual operations.[74]

PacifiCorp criticizes the maximum-of-averages approach as using the most extreme outlier cap value in the historical record for every month, contrasted with the average of averages method, which includes extreme outlier values in the four-year average but does not rely on them exclusively to set the market cap. PacifiCorp maintains that its proposed market caps better approximate actual sales opportunities, and therefore mitigate the potential for future under-recovery.

Staff, AWEC, and CUB oppose the market cap change. CUB provides several possible reasons as to why GRID over forecasts market sales, such as outlier weather events that are not captured in GRID's weather normalized approach. CUB also suggests that extra generation has been moved to EIM activity, as generation and transmission can either be committed to the EIM, or to a short-term sale, not both.[75] CUB also argues that the new low-cost renewables that have come online in recent years should increase future sales because it is lower cost than the market price.[76]

[72] PacifiCorp Opening Brief at 10.
[73] PacifiCorp Opening Brief at 6.
[74] PacifiCorp Opening Brief at 7.
[75] CUB/200, Jenks/3-8.
[76] CUB/100, Jenks/4.

Staff, AWEC, and CUB also argue that PacifiCorp has not demonstrated that is has chronically over forecast off-system sales in recent TAMs and that the over forecast PacifiCorp presented in this case appears larger when viewed in isolation. Staff and CUB claim that PacifiCorp has an offsetting over forecast of purchases, which are a cost to customers.[77] Staff and CUB state that the dollar amounts are similar and offsetting when the missed net margins on sales are compared to cost of over forecasted purchases. CUB explains that the costs associated with the PPA or fuel used for sales are also recovered in NPC, so to determine the magnitude of the over forecast PacifiCorp needs to identify the missing net margin from sales, not the missing revenue.[78] AWEC finds that off-system sales are not over-estimated when adjusted for bookouts.

CUB, AWEC, and Staff suggest alternatives. CUB states that it looked for a methodology that would be forward looking and did not find one. CUB suggests for each market hub, PacifiCorp set the cap at the mid-point between the average of averages approach and the maximum of averages approach.

Staff asserts the best solution is to make the model more realistic and that to prove a different approach is superior, PacifiCorp should have produced GRID runs from 2013 to 2020 using the average of averages approach.[79] Staff recommends leaving the market caps unchanged and decreasing NPC by $5.1 million (Oregon-allocated). Staff's alternative recommendation is to calculate market caps with the "third quartile of averages" which reduces NPC by $3.4 million (Oregon-allocated) by averaging the two highest values of the four highest monthly sales at each hub. Staff reasons that this will still portray market depth while also addressing PacifiCorp's concern about GRID's over forecast of sales. Staff states the change in market caps should be for one year only, and how to approach market caps should be considered with Aurora next year.

c. Resolution

We begin by considering our statements from the rate case order:

> Between now and 2024, PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under recovery. The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast, just as it did in the 2016 TAM when it introduced the DA/RT mechanism to increase the volume and modeled cost of balancing

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[77] Staff Reply Brief at 5.
[78] CUB/200, Jenks/6 ("A utility will generally sell into the market if the market price is greater than the incremental cost of production and transmission. The margin on the sale—the difference between the price and the incremental cost of production and delivery—is what counts towards the bottom line.").
[79] Staff Reply Brief at 7.

> transactions to increase GRID's balancing costs. PacifiCorp does not necessarily need to develop a complex new adjustment, but may be able to improve its forecast accuracy with straightforward inputs or limits. For example, Staff shows that PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a "gross over-estimation of the sales benefit". PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. With PacifiCorp's upcoming transition to a new power forecast model (AURORA) there may be other options for improving PacifiCorp's forecast that will emerge once the parties begin training with the model.[80]

In the rate case order we described PacifiCorp's annual opportunity to "improve its forecast" and "improve its forecast accuracy". Ideally, this could occur through a fix to make the modeling itself more accurate, and not an out-of-model manual adjustment that changes every year to limit the model. We are optimistic that improved, more accurate modeling may be realized with the rollout of Aurora in PacifiCorp's 2023 TAM. Because of the imminent change to a new model and the unknown sales level that Aurora will produce, we limit our finding on market caps to the 2022 TAM only.

Next, we consider whether PacifiCorp has demonstrated that its average of average market cap proposal will make GRID's forecast of sales better or more accurate. As CUB pointed out, none of the market cap proposals forecast the level of market sales expected on a going forward basis. GRID's modeling cannot predict the depth of the market or whether the market demand will be there. All of the proposals before us are approximations of market depth based on past actual sales.

We look to the record to determine which proposal is most accurate based on the information available. PacifiCorp's table comparing its overall annual forecast of sales volume compared to actual sales volume shows that overall actual sales are approximately 6 million MWh per year for the last four years while its forecasted amount of sales is close to 13 million MWh over the same period. This data supports PacifiCorp's position that GRID does over forecast off-system sales with the maximum of averages market caps. The data alone also supports PacifiCorp argument that from a rate-setting perspective, the average of averages is reasonable as it most closely

[80] *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 130 (Dec 18, 2020) (citations omitted).

approximates the historical average over the last four years.

	Short-Term Sales (MWh)		
	Actual[1]	Forecast[2]	(Below)/Above Forecast
2012	7,746,564	9,360,282	(1,613,719)
2013	7,867,127	11,529,969	(3,662,842)
2014	8,130,895	11,152,711	(3,021,816)
2015	7,619,541	11,420,069	(3,800,527)
2016	6,018,797	12,139,446	(6,120,649)
2017	6,651,663	13,806,284	(7,154,620)
2018	7,765,501	13,977,258	(6,211,757)
2019	4,947,298	15,623,544	(10,676,246)
2020	4,885,911	13,887,647	(9,001,736)
2021		8,845,440	
2022 (Direct Average of Averages)		6,693,996	
2022 (Direct Maximum of Averages)		8,055,722	

We must also consider the parties' arguments which persuasively demonstrate that there are other related and offsetting costs in PacifiCorp's forecast. Important to our determination is the parties' explanation (and PacifiCorp's data) showing an offsetting over forecast of purchases.[81] We also agree with CUB's explanation that the data overstates the problem because of how NPC covers the PPA or fuel price of over forecast sales, so PacifiCorp's under recovery is limited to the margin on the sale (the difference between the production cost and the sale price). PacifiCorp's data also shows that in 2021 and 2022 GRID produced a lower volume of sales even with the maximum of averages market cap, and it is too soon to know if that adjustment will bring the forecast closer to actuals.

We conclude that the most reasonable approach for the 2022 forecast is a compromise position. We adopt Staff's alternative recommendation, which CUB also supports as reasonable, to calculate market caps with the "third quartile of averages" which reduces NPC by $3.4 million (Oregon-allocated) by averaging the two highest values of the four highest monthly sales at each hub. This adjustment applies only to the 2022 TAM. We will evaluate the reasonableness of Aurora's forecast when we see it in the 2023 TAM.

2. *Nodal Pricing Model Benefits*

a. Overview

PacifiCorp states that net power costs and nodal pricing model (also referred to as NPM) are framework issues in the 2020 Protocol and currently part of the ongoing Multi State Protocol (MSP) negotiations. PacifiCorp notes that the 2020 Protocol contemplates that the nodal pricing model will be used for cost allocation beginning in 2024.[82] PacifiCorp

[81] PAC/400, Staples/23-24.
[82] PAC/1100, Wilding/3.

states that to have the information necessary (*i.e.*, day-ahead, hourly locational marginal prices (LMP)) to allocate NPC using the nodal pricing model, PacifiCorp contracted with the California Independent System Operator (CAISO) to receive optimized day-ahead advisory schedules. PacifiCorp began nodal pricing model service in January 2021 for operations.[83] The day-ahead schedules from CAISO are used to inform PacifiCorp's day-ahead schedules.[84] In this TAM PacifiCorp includes $8.4 million total-company in CAISO service fees for the day-ahead schedules from CAISO.[85]

PacifiCorp explains the differences between the EIM and nodal pricing model. EIM is within the hour and the nodal pricing model is the day-ahead period. The other difference is the footprint; EIM co-optimizes all EIM participants and the nodal pricing model only optimizes PacifiCorp's system.

b. Parties' Positions

Staff asserts the nodal pricing model realizes dispatch benefits beyond GRID's optimization. Staff states that GRID pairs the least-cost generation bubble to serve a load bubble, subject to zonal constraints. In the nodal model each bubble has a locational marginal price (LMP), and the model optimizes generation and transmission together. Staff states that GRID selects the cheapest cost resource to serve load, while a nodal model would instead select the cheapest means to serve. Staff believes that the additional granularity of the nodal pricing model goes beyond GRID's perfect optimization because it identifies the impact each generator has on the overall system.[86]

Staff asserts that the efficiency gains resulting from the new dispatch logic should be passed on to customers in 2022 NPC rates because customers are paying costs related to the nodal pricing model in rates. Staff states that, despite PacifiCorp's representation about nodal pricing model benefits in the 2020 Protocol, PacifiCorp has not quantified the operational benefits. Staff argues that in another circumstance, the company's participation in the EIM, where anticipated benefits associated with a new program were difficult or impossible to quantify, the Commission approved the parties' agreement to match the costs and benefits in rates for PacifiCorp's first year.[87]

[83] PAC/400, Staples/76.
[84] PAC/1100, Wilding/3.
[85] PacifiCorp Opening Brief at 22.
[86] Staff/1300, Gibbens/5.
[87] *In the Matter of PacifiCorp 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 (Oct 1, 2014).

Staff recommends that for the 2022 TAM, benefits be set equal to costs and PacifiCorp's NPC be reduced by $8.4 million total-company, as a proxy for the benefits realized in actual operations from the nodal pricing model.[88] Staff states this is a one-time adjustment, because once PacifiCorp changes to the new nodal model Aurora, the savings realized by CAISO's nodal dispatch logic will be captured by Aurora and customers will realize those benefits through a standard model run. As an alternative, Staff recommends that PacifiCorp perform a TAM model run with the same inputs as GRID, using the Aurora model. The difference would provide parties with information necessary to address the issue in the 2022 PCAM.[89]

c. PacifiCorp's Response

PacifiCorp describes its day-ahead set-up process. In relevant part, CAISO provides PacifiCorp with an advisory day-ahead dispatch schedule. PacifiCorp uses the schedules to create the bids for the EIM market. PacifiCorp checks its dispatch against its optimization model (Gentrader) and may make adjustments in Gentrader to ensure the optimization results from Gentrader are consistent with the nodal pricing model.[90]

PacifiCorp explains that CASIO uses a flow based nodal model that produces a LMP at each node for the day ahead schedules it provides to PacifiCorp. PacifiCorp's Gentrader model uses a zonal topology. PacifiCorp states the benefits from the nodal dispatch are from having a more efficient day-ahead setup, with more transparency into transmission rights. PacifiCorp states this results in fewer changes between the day-ahead setup and real-time dispatch, and thus lower NPC from avoiding those changes.[91]

PacifiCorp disagrees with Staff that there are benefits incremental to the GRID model. PacifiCorp states the GRID model does not include costs associated with changes between the day-ahead setup and real-time dispatch because the GRID forecast is based on a single balancing step and a single set of inputs. PacifiCorp compares this to the intra-hour benefits of the EIM that are already captured in GRID. Because GRID is an hourly model and does not include intra-hour changes, there are no costs in the GRID forecast for those intra hour changes. Accordingly, PacifiCorp continues, the Commission decided against any sort of adjustment to the GRID model to account for the EIM benefits associated with more efficient intra-hour dispatch.

[88] Staff/1300, Gibbens/6.
[89] Staff/1300, Gibbens/7.
[90] PAC/1100, Wilding/4-5.
[91] PAC/1100, Wilding/5.

PacifiCorp claims that Staff's alternate recommendation that would compare an Aurora forecast to the GRID forecast is not feasible. PacifiCorp maintains there is not sufficient time to produce an Aurora forecast and even if Aurora lowers NPC it could be due to numerous other changes.

Lastly, PacifiCorp asserts the purpose of the nodal pricing model has been previously discussed with stakeholders in docket UM 1050. PacifiCorp states that as a signatory to the 2020 Protocol, Staff agreed that the pursuit of the nodal pricing model was prudent.[92] PacifiCorp further notes that in the 2020 Protocol proceeding, Staff did not argue that the nodal pricing model would also create NPC savings that would be imputed into the TAM.

d. Resolution

After a detailed review of the arguments on this issue, we find that it would be appropriate to make an adjustment to PacifiCorp's filing to reflect some level of cost savings in 2022 NPC. We find that PacifiCorp's approach of forecasting no incremental benefit from its NPM is not well-supported by the record in this case, and that Staff has provided evidence that some incremental cost savings should be expected. We decline to adopt Staff's recommendation to assume that the expected benefit would be equal to the total costs included in PacifiCorp's filing, however, and instead find that PacifiCorp's filing should be adjusted to reflect expected savings of half of its proposed costs.

ORS 757.210(1)(a) establishes the burden of proof applicable in this case, and provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable." To meet its burden, PacifiCorp must demonstrate that its proposed rates are just and reasonable, by including an appropriate expectation of benefits that will come about from the NPM.[93] Here, PacifiCorp explains there are actual benefits from the nodal pricing model, and that "the benefits of NPC are embedded in actual NPC."[94] PacifiCorp made similar statements in its 2019 filing of the 2020 Protocol.[95] Staff agrees, and also maintains that the nodal pricing model is expected to provide benefits to NPC. The question in this case, then, is whether PacifiCorp has reasonably included those expected benefits in its proposed rates.

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[92] PacifiCorp Opening Brief at 22.
[93] Order No. 20-473 at 5.
[94] PAC/1100, Wilding/9.
[95] PAC/1100, Wilding/10 (citing *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket UM 1050, PAC/300, Wilding/10-11 "[t]he potential operational cost savings will be the result of a more efficient day-ahead setup and the cost savings will be embedded in the actual NPC. These potential cost savings will be impossible to accurately and precisely track as the calculation of such savings would rely on a counterfactual setup of the system without the NPM.").

In order to determine if PacifiCorp's proposed rates are just and reasonable, the Commission would need to know the type and amount of benefits that the nodal pricing model is delivering. Rather than provide such a demonstration, however, PacifiCorp asserts that there are no incremental benefits beyond those that are already included in its GRID model's estimate of NPC. In support of this argument, PacifiCorp explains that:

> GRID has perfect foresight or zero uncertainty. This means that for every hour of the year, GRID knows the exact load (which does not change) and GRID knows the exact dispatch cost of each generation resource. Because of this perfect knowledge, GRID ensures that in its modeling, in every hour, the lowest cost resources will be dispatched, subject to transmission constraints.[96]

In response, Staff argues that the nodal pricing model finds savings as a "better informed model that can optimize to a higher level of precision."[97] Staff explains that the nodal pricing model has the "ability to identify the impact each generator has on the overall system"[98] with "more granular dispatch information resulting in anticipated operational cost savings."[99] Staff explains how GRID divides PacifiCorp's service territory:

> [I]nto twelve load centers and twelve resources bubbles connected via transmission bubbles. This means that GRID does not have the granularity to identify the impact of a single unit on the entire transmission system. GRID only optimizes each bubble subject to the constraints; therefore, the impact of any resource within a bubble to the transmission system is unknown in GRID. GRID simply is not complex enough to fully take into account the limits of the transmission network.[100]

We understand Staff's argument to be that the nodal pricing model realizes benefits by using information about transmission constraints to shape dispatch, not just to limit a path as GRID does. Even PacifiCorp seems to acknowledge this benefit when it explained the nodal pricing model schedules provide traders "more transparency into PacifiCorp's transmission scheduling rights."[101]

[96] PAC/400, Staples/78.
[97] Staff/900, Gibbens/11.
[98] Staff/900, Gibbens/12.
[99] Staff/900, Gibbens/8.
[100] Staff/1300, Gibbens/3.
[101] PAC/1100, Wilding/5.

We find that PacifiCorp did not adequately rebut Staff's position that there are expected benefits from the nodal pricing model that are incremental to those forecast by GRID. Instead, PacifiCorp relied on its generalization that GRID already takes into account the benefits, without specifically addressing how the differences between GRID and the nodal pricing model could be reconciled with the company's position. On this record, we find that it would be appropriate to make an adjustment to PacifiCorp's rates to reflect an assumption of incremental savings that will accrue from the nodal pricing model. In short, PacifiCorp did not carry its burden of proof on this issue to demonstrate that all of the benefits were already included in GRID.[102]

Although Staff rebutted PacifiCorp's position, we decline to find that the assumed benefit should be deemed to be a full offset of the $8.4 million in projected costs associated with PacifiCorp's use of the nodal pricing model. We find that PacifiCorp's decision to pursue the nodal pricing model is generally reasonable, and therefore we expect that over time its benefits would more than offset its costs. At the same time, we recognize that the benefits of a new system may not necessarily, in 2022, produce benefits that fully offset the program's initial costs.

We find it appropriate to include a $1.09 million reduction to Oregon-allocated NPC as a proxy for nodal pricing model benefits in 2022, reflecting that Staff rebutted PacifiCorp's position that there are no incremental benefits, but also reflecting our determination that those incremental benefits may not be expected to fully offset costs in 2022. This adjustment is limited to the 2022 TAM as we anticipate nodal pricing model benefits across PacifiCorp's two BAAs will be captured with the implementation of Aurora for planning in the 2023 TAM. We note that, over time, the opportunity may arise to co-optimize day ahead planning with additional BAAs. At such time, we expect PacifiCorp to make a reasonable estimate of forecasted benefits to NPC, as it has for forecasted benefits during the initiation and market footprint expansion of the EIM.

3. Fly Ash Revenues

a. Overview

Fly ash is a by-product of the combustion of burning pulverized coal in electric power generating plants. PacifiCorp collects fly ash and is then able to sell the by-product to be used in construction. Fly ash is used by the construction industry to develop concrete,

[102] *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 5 (Dec 18, 2020) ("If the company fails to meet that burden, either because the opposing party presented persuasive evidence in opposition to the proposal, or because PacifiCorp failed to present adequate information in the first place, then PacifiCorp does not prevail because it has not carried its burden of proof.").

bricks, and other building supplies. Because fly-ash is a by-product of coal combustion, its production fluctuates with power production. PacifiCorp produces fly-ash mainly from the Jim Bridger plant, with small amounts being sold from Naughton, Craig, and previously, Cholla.

Presently, fly ash revenues are included in PacifiCorp's 2020 rate base, as decided in docket UE 374. During UE 374, PacifiCorp projected $4,256,000 total-company in national fly ash sales, which was included in base rates.[103] However, according to PacifiCorp's most recent FERC Form 1, the company has nationally made fly ash sales of $3,445,036 total-company in the first quarter of 2021.[104] At its current pace, PacifiCorp is projected to make national fly ash sales of $13,780,144 total-company.[105] This is significantly higher than the projected $4,256,000 total-company in annual revenues included in base rates in UE 374.

The parties' arguments on fly ash revenues involve two past TAM orders. The 2009 TAM Guidelines with the 2010 Update listed specific other revenues to include in the TAM. The 2012 contains guidance on the TAM Guidelines with the statement that "While ICNU may certainly advocate for changes to the TAM, such as the changes proposed here, the TAM guidelines make clear that such changes are to be appropriately addressed in a general rate revision docket or other proceeding, not part of a stand-alone TAM proceeding."[106]

b. Parties' Positions

Staff and AWEC assert that due to a material increase in revenues associated with fly ash sales as compared to the amounts included in current base rates, PacifiCorp's fly ash revenues be considered in the Other Revenue forecast of the TAM.

AWEC and Staff argue that increased fly ash sales should be reflected in the TAM because fly ash is a direct byproduct of burning coal, and therefore is directly related to net power costs.[107] AWEC claims the Commission should include fly ash sales in Other Revenues as this category already includes items that are directly related to new power costs. AWEC explains that while the TAM Guidelines Exhibit B does include examples of select revenue baselines, nowhere in Order No. 10-363, nor the Stipulation underlying

[103] AWEC/200, Mullins/24.
[104] *Id.* at 24.
[105] *Id.*
[106] *In the Matter of PacifiCorp 2012 Transition Adjustment Mechanism,* Docket No. UE 227, Order No. 11-435 at 6 (Dec 21, 2011).
[107] AWEC/200, Mullins/25.

it, is it specified that those, and only those, sources of revenue identified in Exhibit B would be considered as Other Revenue for purposes of TAM forecasting.

AWEC and Staff believe the increased revenue from fly ash is a multiyear trend and is likely to continue through 2022. PacifiCorp's fly-ash revenues have increased by over 60 percent in the past year and there is strong demand for fly-ash in the US.[108] AWEC states that prior stand-alone TAM proceedings have not presented a factual scenario with a 4-fold increase above the rate case level. AWEC and Staff reason that including these revenues in the TAM ensures that benefits are captured fully between rate cases.

AWEC advocates developing a fly ash sales forecast based on 2020 fly ash sales of $6,851,586 total-company, adjusted to remove the historical sales from Cholla, for $6,504,276 total-company.[109] The higher sales of 2021 would roll into the 2023 TAM forecast.[110] After updating the Other Revenue calculation, AWEC suggests reducing Oregon-allocated TAM revenues by $949,615.[111] Staff agrees with AWEC's proposal for forecasting.

Staff adds that PacifiCorp should update its "Other Revenues" to include any other appropriate revenues in the indicative November filing. Staff is concerned that PacifiCorp has been selectively updating Other Revenues in the TAM and any other new contracts that will increase revenues in 2022 and are appropriate for the TAM should be in this year's November filing.

c. PacifiCorp's Position

PacifiCorp responds that fly ash revenues are in UE 374 base rates and have never been in the TAM. PacifiCorp states that many items in base rates have fluctuated since the rate case.

PacifiCorp also responds that AWEC's proposal is contrary to the TAM Guidelines because revenue is only included in Other Revenue if Order No. 10-363 specifically identifies the revenue source, and fly ash revenue have never been added. PacifiCorp states that initially only one revenue item was included in the stand-alone TAM filing, which was the Little Mountain steam sales. The following year, the 2011 TAM stipulation provided for five additional specific items, including: storage and exchange agreements for the Seattle City Light; Stateline and Foote Creek projects; revenues from

[108] AWEC Reply Brief at 15.
[109] AWEC/100, Mullins/21.
[110] AWEC/200, Mullins/25.
[111] AWEC/100, Mullins/21.

the BPA contact associated with the South Idaho Exchange; steam revenues for Little Mountain; and royalty revenues for the GP Camas contract.

PacifiCorp concludes that since the 2011 TAM, the Commission has never recognized additional Other Revenues in the TAM. In 2012, the Commission rejected ICNU's attempt to include updated retail sales revenue. If AWEC wants to include additional revenues in the TAM, PacifiCorp argues it must propose a change to the TAM Guidelines in a general rate case.

d. Resolution

In general, the TAM has long been a highly contested proceeding, and we are wary that opening up the TAM Guidelines could lead to asymmetry. Identifying a single cost or revenue that varies from base rates, without updating base rates as a whole or adjusting for other variations, could result in TAM updates that are not equal, with an imbalance between the cost items that favor PacifiCorp with the revenue items that favor customers. If the revenues are substantial, we recommend that Staff seek to use a deferral mechanism, rather than an adjustment to TAM rates, which we would review under our normal approach to deferrals.

For fly ash revenue specifically, AWEC and Staff have not shown that fly ash revenues are directly related to power production such that they should be included in the TAM. Because we know the production level from PacifiCorp's coal fleet has declined, it is reasonable to conclude that PacifiCorp's increased fly ash revenues are correlated with construction demand and not power production. We decline to require a special update to Other Revenues in this TAM, for fly ash revenues, or any other item.

4. Qualifying Facilities Overforecast

a. Overview

Staff explains that, under PURPA, the Public Utility Regulatory Policies Act of 1978, investor-owned utilities are required to purchase power from Qualifying Facilities (QFs), using rates established by the state regulatory commissions.[112] QFs are one of the most expensive resources on PacifiCorp's system, with average costs in this TAM of approximately [redacted]/MWh.[113] We last considered PacifiCorp's QF forecast in the 2018 TAM when we adopted CUB's QF forecast methodology to account for QF delays (Contract Delay Rate - CDR). We recognized that PacifiCorp does not receive accurate

[112] Staff/500, Zarate/8.
[113] Staff/500, Zarate/13; CUB/102, Jenks/1.

information from QF developers about expected online dates and implemented the CDR to apply a rolling three-year average of delay days to the forecasted online date for new QFs.[114]

b. Parties' Positions

Staff is concerned with the historical relationship of actual QF MWh produced to PacifiCorp's projections. PacifiCorp provided summary statistics of QF projections to actual history that Staff presents in this table:[115]

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Staff concludes from the data that PacifiCorp has a history of overestimating the MWhs produced from PURPA QF projects and once the CDR methodology was implemented in the 2019 TAM the overestimate declined but remained substantial.

Staff recommends an adjustment to reduce PacifiCorp's QF costs. Staff calculates that PacifiCorp over-recovered QF costs in 2020 by $3.2 million, Oregon-allocated, and Staff reduces that amount by the cost of Mid-C power needed to replace the QF MWh to serve load. Staff ultimately recommends a $1.53 million, Oregon-allocated reduction to PacifiCorp's QF costs.

c. PacifiCorp's Response

PacifiCorp responds that it forecasts QF costs in the TAM based on each individual contract. PacifiCorp states that the contracts vary, some may specify an exact quantity of capacity or energy, or a range bounded by a minimum and maximum, or it may be based on actual operations. PacifiCorp states that for QFs less than or equal to 10 MW, the forecast uses the actual delivery schedule. For renewable QFs over 10 MW, the QF

[114] *In the Matter of PacifiCorp 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 (Nov 1, 2017).
[115] Staff/500, Zarate/12.

forecast is determined the same as the forecast for owned wind generation – for the first four years PacifiCorp uses the developer's P50 estimate from the interconnection agreement. After four years PacifiCorp uses actual performance data based on the full history.[116] PacifiCorp maintains that it is using the best available information from each QF project.

PacifiCorp opposes Staff's adjustment. PacifiCorp argues the adjustment is just a reduction equal to the 2020 over forecast. PacifiCorp states that Staff improperly requests a historical true-up of only one element of NPC, when overall NPC was eight percent more than forecast.

d. Resolution

We will not adopt a QF adjustment in this TAM, consistent with our other findings rejecting adjustments that resemble a true-up of one line item of NPC to align with actual past levels. Nonetheless, we are concerned about PacifiCorp's consistent over forecast of QFs as shown in Staff's data table. In the 2023 TAM we direct PacifiCorp to update the table above with 2021 data, and to address the question of why it has continued to over forecast QFs in recent years. It is our understanding that there are two possible errors with the QFs: the lag in online dates realized for new QFs; or an error in forecasting for existing QFs. It is possible that the 2020 data is still reflecting a lag from new QFs even after the CDR was applied. If new QFs are the issue, then the 2021 and 2022 data should have a more accurate forecast because no new QFs have come into the 2021[117] or 2022[118] forecast. If the error continues in 2021, then PacifiCorp should investigate whether a category of old, non-wind QFs are skewing the forecast and PacifiCorp should address how it can improve the accuracy of its QF forecast.

5. Load Forecast

a. Parties' Positions

SBUA states the 2022 load forecast used in the PacifiCorp's calculation of NPC reflects an increase in Oregon load compared to the 2021 forecast loads in the 2021 TAM. SBUA states that due to the increase in Oregon load, PacifiCorp anticipates it will need to collect approximately $3.3 million more than what was approved in the 2021 TAM. SBUA argues that evidence in this docket puts this forecast into question or supports close examination of the load forecast in the context of the 2020 Protocol 3.1.9 involving

[116] PAC/400, Staples/43.
[117] *In the Matter of PacifiCorp 2021 Transition Adjustment Mechanism*, Docket No. UE 375, PAC/100, Webb/15 (Feb 14, 2020) ("No new QFs are forecast to come online in the 2021 TAM forecast period.").
[118] PAC/100, Webb/20 ("No new QFs are forecast to come online in the 2022 TAM forecast period.").

load-based dynamic allocation factors. SBUA asserts the return to pre-COVID employment is not projected until the fourth quarter of 2022.[119] SBUA recommends we find that any increase in the TAM is not justified.

PacifiCorp responds that its load forecast is robust, and no other party to this proceeding has questioned the general reasonableness of the Company's load forecast. PacifiCorp argues that SBUA has not provided any evidence to address specific issues with the load forecast or employment in PacifiCorp's service territory. PacifiCorp asserts the Commission should reject SBUA's proposal and recommendations as insufficiently supported in the record.[120]

b. Resolution

SBUA has not shown any inaccuracies in PacifiCorp's load forecast, or in PacifiCorp's application of the 2020 Protocol to the load forecast.[121] We are unable to make a more specific finding on SBUA's arguments due to the limited explanation in the record. We briefly note there may be a misunderstanding of PacifiCorp's testimony on its load variance in the 2022 TAM. PacifiCorp states that "due to the increase in Oregon load, the Company anticipates it will need to collect approximately $3.3 million more than what was approved in the 2021 TAM."[122] Another explanation is that as a result of the load increase, PacifiCorp will collect $3.3 million more than was projected in the 2021 TAM. The $3.3 million surplus was subtracted from PacifiCorp's NPC increase of $4.5 million, resulting in PacifiCorp's initial filing showing a proposed $1.2 million increase in Oregon-allocated revenue requirement for 2022.[123] We note that this calculation is part of each TAM and we find that PacifiCorp's calculation appears correct in the 2022 TAM.[124]

6. Direct Access Opt-Out Charge

a. Overview

The general issue in this proceeding is that Calpine proposes that PacifiCorp's opt-out charge should be allowed to go negative to credit direct access customers who leave the

[119] SBUA Opening Brief at 5-7.
[120] PacifiCorp Rebuttal Brief at 49-50.
[121] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket No. UM 1050, PAC/101 (Dec 3, 2019).
[122] PAC/100, Webb/3.
[123] PAC/101, Webb/1.
[124] PAC/401, Staples/1.

system. We provide background on the direct access charges and credits before moving to the parties' positions in this case.

Customers that choose the one and three year opt-out program must renew at the end of the term. These customers pay actual Schedule 200 costs for fixed generation and a transition adjustment for Schedule 201 costs for variable power costs that is the difference between the power cost charge and the value of the freed-up energy.[125] In the past the transition adjustment has been a small charge or a small credit, this year PacifiCorp's sample transition adjustment calculation is an average credit of $14.27/MWh during heavy load hours.[126]

Customers that choose the five-year opt-out program permanently leave PacifiCorp's system. These direct access customers pay five years of the same costs described above – actual Schedule 200 fixed costs, and a transition adjustment that is the net cost or credit for Schedule 201 power costs offset by the value of the freed-up energy. Direct access customers in PacifiCorp's five-year program also pay a consumer opt-out charge. The consumer opt-out charge is a forecast of the Schedule 200 fixed costs for years six through ten, brought forward into years one through five, offset by the transition adjustments projected for years six through ten that net projected power costs against the value of the freed-up energy.[127] Calpine explains the current 2021 opt-out charge is $3.76/MWh.[128]

At issue in this proceeding is that PacifiCorp has capped the value at zero for the opt-out charge, so unlike the transition adjustment, it cannot be a credit. If the calculation is allowed to go negative, Calpine explains the 2022 sample opt-out charge would provide for a credit ranging from $1.62/MWh to $4.99/MWh.[129]

b. Parties' Positions

Overall, Calpine, AWEC, and Staff assert that PacifiCorp should utilize its approved methodology to calculate the opt-out charge in a manner that allows it to go negative. Staff recommends this for the 2022 TAM only, and that the Commission more fully address the issue in the docket UM 2024 proceeding. PacifiCorp and CUB state that if the opt-out charge value becomes negative then PacifiCorp should set it at zero in this proceeding and parties may more fully examine this issue in docket UM 2024.

[125] *In the Matter of PacifiCorp 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 12 (Dec 11, 2015).
[126] Calpine Solutions/100, Higgins/10-11.
[127] PAC/900, Meredith/3; Calpine Solutions/101.
[128] Calpine Solutions/100, Higgins/14.
[129] Calpine Solutions/100, Higgins/19.

Calpine and AWEC argue that PacifiCorp should not artificially constrain the opt-out charge. Calpine believes the direct access opt-out charge is essentially the same thing as the transition adjustment, and that if PacifiCorp has a projected benefit for years six through ten then the charge should be a credit, like the transition adjustment. Calpine states OAR 860-038-0160(1) requires PacifiCorp to pay a credit to the customer if the net-value is below zero and that PacifiCorp must use the ongoing valuation method approved in docket UE 267 to calculate the consumer opt-out charge.

Calpine and AWEC explain that when the opt-out charge becomes a credit it is because there are net power costs savings attributed to the departed opt-out load in years six through ten, and consequently, costs are not shifted to non-direct access customers.[130] Calpine and AWEC believe that a negative opt-out charge is not a policy issue for docket UM 2024, it is a math issue for this proceeding.[131]

Staff generally agrees with Calpine and AWEC that PacifiCorp should use its approved methodology to calculate the consumer opt-out charge as a freely floating mechanism that can go below zero for this for this proceeding. Staff notes that PacifiCorp has presented no evidence of cost-shifting associated with allowing the charge to go negative. Staff recommends a final determination on the issue can be made in docket UM 2024.[132]

PacifiCorp responds that the direct access opt-out charge is a distinct type of charge from a transition adjustment, and that it should be capped at zero to effectuate its purpose of reimbursing the utility for stranded costs.[133] PacifiCorp and CUB believe that the opt-out charge is intended to prevent cost-shifting to protect the non-participating cost of service customers.[134] PacifiCorp and CUB claim it should be a charge because that was how it was presented and adopted. PacifiCorp argues the opt-out charge was created as its own mechanism separate from the transition adjustment, and therefore should be only a charge.[135]

CUB explains that in docket UM 2024 its position is that the direct access program has already shifted costs from direct access participants to cost-of-service customers because direct access participants purchase energy on the market that does not capture the capital costs of the generating plant. PacifiCorp and CUB explain that other policy issues are being addressed in docket UM 2024 such as if direct access customers must pay for coal

[130] Calpine Solutions/200, Higgins/4.
[131] AWEC/200, Mullins/27.
[132] Staff Reply Brief at 30.
[133] PAC/900, Meredith/2.
[134] CUB Reply Brief at 14.
[135] PAC/1500, Meredith/2-3.

plant closure and decommissioning costs. PacifiCorp and CUB reason that enabling the opt-out charge to go negative is a significant policy issue that should be addressed in docket UM 2024. PacifiCorp and CUB conclude that, in the meantime, it is inappropriate for cost-of-service customers to further subsidize direct access customers.

c. Resolution

We will adopt Staff's position and let the opt-out charge go negative until we fully address this issue in docket UM 2024. We recognize there have been delays in docket UM 2024 and the difficult questions of a cross-subsidy between direct access and cost-of-service customers can be addressed in that proceeding.

In the meantime, we are persuaded by Calpine and AWEC that there is no clear prohibition on the opt-out charge becoming a credit. With our narrow review in this proceeding, it appears that PacifiCorp's fixed costs, and the net value of freed-up energy that offsets the fixed costs, could be similar in years one through five as years six through ten. It follows that the calculation of the differential in years six through ten should function the same as the calculation in years one through five, when the transition adjustment is allowed to go negative.

Our decision here is not precedential with respect to whether we would adopt a policy to direct access that pays customers to leave the system. Our decision in this case is limited to PacifiCorp's TAM proceeding until docket UM 2024 is resolved, and our decision is that PacifiCorp should conduct the calculation as it always has, without adding a constraint on the final value.

d. Renewable Energy Credit (REC) Retirement

Calpine and PacifiCorp agree on a new approach for REC transfers in response to a HB 2021 provision that allows bundled RECs to be retired by the utility on behalf of Electricity Service Suppliers (ESS)for direct access customers. The parties describe a change from the current REC transfer procedure to a REC retirement procedure. PacifiCorp states it will transfer bundled and unbundled RECs into a Western Renewable Energy Generation Information System (WREGIS) retirement subaccount that is specific to each ESS. PacifiCorp agrees to the provisions proposed by Calpine.[136] As requested by Calpine, we approve the parties' agreement.

[136] Calpine/200, Higgins/10-11; PAC/1400, Wiencke/2.

IV. NEXT STEPS

We briefly memorialize a few next steps that the parties agreed on.

A. 2023 TAM Filing Date

The parties agree that PacifiCorp will file the 2023 TAM on March 1, 2022. This date allows PacifiCorp to implement the December 31 forward price curve in its NPC forecast. As requested by PacifiCorp, we agree that PacifiCorp can forego an April 1, 2022 update and that PacifiCorp may provide its Schedule 296 calculation on May 30, 2022.[137]

B. DA/RT Update

The parties agree that PacifiCorp will conduct workshops addressing DA/RT and the transition to Auora prior to filing the 2023 TAM. PacifiCorp plans to conduct workshops on the continued value of the DA/RT adder and its inclusion in the Aurora model.[138]

C. Aurora

PacifiCorp also plans to conduct a workshop outlining the Aurora modeling process itself to promote understanding between Staff, intervenors, and the company about the modeling process ahead of the 2023 TAM.[139]

V. ORDER

IT IS ORDERED that:

1. Advice No. 21-008 is permanently suspended.

2. PacifiCorp, dba Pacific Power, update its net power costs to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism NPC for calendar year 2022 and file its tariffs to be effective January 1, 2022.

[137] PAC/1000, Staples/56-57.
[138] PAC/400, Staples/32.
[139] *Id.*

3. The directives contained in this order be implemented by PacifiCorp, dba Pacific Power, as described above.

Made, entered, and effective Nov 01 2021.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1301

Docket No. UE 390 AWEC/100
Opening Testimony of Bradley G. Mullins

September 1, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp d/b/a Pacific Power	)
	)
2022 Transition Adjustment Mechanism	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

June 9, 2021

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit AWEC/101.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's proposed Transition Adjustment Mechanism ("TAM") revenues, including Net Power Costs ("NPC"), for calendar year 2022. Specifically, I discuss my review of PacifiCorp's proposed $1,214,140 revenue increase associated with the 2022 TAM filing. Relevant discovery responses may be found in Exhibit AWEC/102.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are summarized in Table 1, below, followed by brief descriptions of each issue.

Table 1
AWEC Proposed TAM Adjustments
($000)

1	**Initial Filing**	**1,214,140**
2	Adjustments	
3	PTC Rate	(2,649,684)
4	Market Caps	(5,229,355)
5	Other Revenues	(949,615)
6	BCC Materials & Supplies	(785,644)
7	**Total Adjustments**	**(9,614,299)**
8	**Adjusted**	**(8,400,159)**

Production Tax Credit Rate: I recommend updating the production tax credit rate for 2022 to 2.6¢/kWh.

Market Caps: I recommend maintaining the currently approved methodology for Market Caps because no evidence or analysis was presented to justify a change.

Other Revenues: Consistent with past stand-alone TAM filings, I recommend PacifiCorp continue to update its Other Revenues forecast in this proceeding. I also recommend that fly ash sales be considered in the Other Revenue forecast.

Bridger Coal Company Materials & Supplies: I recommend an adjustment for the materials and supplies forecast at Bridger Coal Company, recognizing the fact that PacifiCorp has consistently over-forecast those amounts by a significant margin in past proceedings.

II. PRODUCTION TAX CREDIT RATE

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO PRODUCTION TAX CREDITS.

A. PacifiCorp's TAM filing assumes a PTC rate equal to 2.5¢/kWh for the 2022 forecast period. The 2.5¢/kWh rate was acknowledged on April 27, 2021, by the Internal Revenue Service ("IRS") as the PTC rate for 2021.[1/] Notwithstanding, in 2022—the year in which the proposed net power costs at issue in this proceeding will be in effect—the PTC rate will increase to

[1/] Federal Register Vol 86, No 79, page 22300-22301 (Apr. 27, 2021).

2.6¢/kWh, as discussed below. Accordingly, I recommend updating PacifiCorp's forecast to be based on a 2.6¢/kWh PTC rate. The impact of using a 2.6¢/kWh PTC rate is a $2,649,684 reduction to the Oregon-allocated TAM revenues.

Q. WHAT CAUSES THE PTC RATE TO CHANGE FROM YEAR-TO-YEAR?

A. The PTC rate is established pursuant to Internal Revenue Code ("IRC") § 45.[2/] The PTC rate was first authorized in 1993 and established at a baseline of 1.5¢/kWh. To account for inflation, the IRS adjusts the PTC rate each year by applying an "inflation adjustment factor." In IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is outlined as follows:

> The term "inflation adjustment factor" means, with respect to a calendar year, a fraction the numerator of which is the [Gross Domestic Product ("GDP")] implicit price deflator for the preceding calendar year and the denominator of which is the GDP implicit price deflator for the calendar year 1992. The term "GDP implicit price deflator" means the most recent revision of the implicit price deflator for the gross domestic product as computed and published by the Department of Commerce before March 15 of the calendar year.[3/]

In addition, when applying the inflation adjustment factor, the credit rate is rounded to the nearest multiple of 0.1¢/kWh. Consequently, while the inflation adjustment factor changes every year, the PTC rate does not necessarily change each year. For example, in 2022, the unrounded PTC rate would need to exceed 2.550¢/kWh to trigger an increase to 2.6¢/kWh.

Q. WHAT WAS THE INFLATION ADJUSTMENT FACTOR FOR 2021?

A. The inflation adjustment factor for 2021 was 1.6878, resulting in an unrounded PTC rate of 2.5317 ¢/kWh. Thus, while the PTC rate rounded down to 2.5¢/kWh in 2021, the unrounded PTC credit rate was within 0.0183¢/kWh of 2.550¢/kWh and rounding up to 2.6¢/kWh.

[2/] 26 U.S.C. § 45(b)(2) (2021).
[3/] IRC § 45(e)(2)(B).

Q. WHAT INFLATION ADJUSTMENT FACTOR WILL RESULT IN AN INCREASE TO THE PTC RATE?

A. The inflation adjustment factor must equal or exceed 1.700 to trigger an increase in the PTC rate to 2.6¢/kWh. Whether this level is achieved, however, depends on the annual GDP implicit price deflator, which, as noted above, is an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. As I discuss below, based on information that is known about the GDP implicit price deflator today, it can be determined that the inflation adjustment factor will be sufficient to cause the PTC rate to round up to 2.6¢/kWh in 2022.

Q. HOW DOES THE GDP IMPLICIT PRICE DEFLATOR DETERMINE THE INFLATION ADJUSTMENT FACTOR?

A. Exhibit AWEC/103 contains an analysis showing how the GDP implicit price deflator is used to calculate the PTC inflation adjustment factor. As noted in IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is a simple fraction.

The numerator of the fraction is equal to the GDP implicit price deflator for the calendar year prior to the tax year. For tax year 2022, for example, the numerator will be based on the GDP implicit price deflator from calendar year 2021.

The denominator of the fraction is equal to the GDP implicit price deflator for 1992, the calendar year prior to the 1993 tax year when the PTC was first implemented.

The denominator of the inflation adjustment factor is a known value. The GDP implicit price deflator for calendar year 1992 was 67.325.[4/] Thus, while the precise value for the inflation adjustment factor for calendar year 2022 is not yet known, the periodically published

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[4/] This is based on the current index values. Note that the baseline year used to establish the GDP implicit price deflator index value has been updated, which can be seen in Exhibit AWEC/103.

GDP price deflator values can be used to determine whether the ultimate inflation adjustment factor will exceed 1.700 in 2022 and trigger an increase to the PTC rate.

Q. WHAT GDP PRICE DEFLATOR VALUE WILL TRIGGER AN INCREASE TO THE PTC RATE?

A. Since the denominator of the inflation adjustment factor is known, it can be concluded that a GDP implicit price deflator of 114.45 or more will result in an inflation adjustment factor of 1.700 and a corresponding increase to the PTC rate to 2.6¢/kWh.

Q. IS ENOUGH DATA AVAILABLE AT THIS TIME TO DETERMINE WHETHER THE GDP IMPLICIT PRICE DEFLATOR WILL EXCEED 114.45 FOR 2021?

A. Yes. Based on the GDP implicit price deflator published for Q1 of 2021, it can be concluded with reasonable certainty that the annual 2021 GDP implicit price deflator will exceed 114.450. Accordingly, it also can be concluded that the 2022 PTC Inflation Adjustment Factor will exceed 1.700, and as a result, the 2022 PTC rate will round to 2.6¢/kWh, consistent with the discussion above.

The annual GDP implicit price deflator represents an average over the course of the calendar year. The annual GDP implicit price deflator is not, for example, based on the year end value. Rather, the amount is calculated over four quarters and the average of those quarterly values is used to derive the annual value.

In 2020, for example, the average annual GDP implicit price deflator was 113.625. Notwithstanding, the Q4 2020 the GDP implicit price deflator index value was higher than that value. In Q4 2020, the GDP implicit price deflator increased to 114.368, within only 0.082 of the threshold value to trigger the PTC rate change under discussion.

As detailed in Exhibit AWEC/103, the GDP implicit price deflator index value increased to 115.514 in Q1 of 2021, exceeding the 114.450 threshold value by a margin of

1.564. Since the annual value is calculated as an average and the threshold value has already been exceeded in Q1 of 2021, the GDP implicit price deflator value would need to decline by a significant amount in each of the three remaining quarters of 2021 for the average annual value to decline back below the 114.450 threshold value. In other words, the economy would need to fall into a recession, with three quarters of unprecedented deflation, for the annual GDP implicit price deflator to decline back below 114.450 and for the PTC rate to remain at 2.5¢/kWh. As I discuss below, the level of deflation necessary for the GDP implicit price deflator index to decline below 114.450 as an annual average—and thus the PTC rate to remain at 2.5¢/kWh—is so unlikely as to be nearly impossible. Therefore, while the precise GDP implicit price deflator for 2021 is not yet known at this juncture, it can be concluded that the average GDP implicit price deflator will exceed 114.50 for 2021 and that the PTC rate will increase to 2.6¢/kWh in 2022.

Q. WHAT MAGNITUDE OF DEFLATION WOULD BE REQUIRED FOR THE GDP IMPLICIT PRICE DEFLATOR TO REMAIN BELOW 114.50?

A. Mathematically, for the GDP implicit price deflator to decline back below 114.50 and thus not trigger an upward rounding of the PTC rate, the economy would need to experience deflation of 0.62% in each of the three remaining quarters of 2021. This calculation is shown in Exhibit AWEC/103. On a cumulative basis, such a scenario would represent deflation of 1.84% over the three-quarter period. Such a level of inflation would have no precedent in modern history, particularly since the abolition of the gold standard in the 1970s. During the period of modern monetary policy, when the dollar has been decoupled from gold prices, there have been only four instances of modest deflation, as measured by the GDP implicit price deflator—and none of those instances have come remotely close to deflation of 1.84%.[5/] In the 2008 financial crisis, for example, the GDP implicit price deflator declined by 0.16%. Further, in Q1 of 2015, modest deflation was experienced, corresponding to a 0.09% reduction to the GDP implicit price deflator. Similarly, in Q1 of 2016, modest deflation corresponding to a 0.07% reduction to GDP implicit price deflator was also experienced. Finally, in Q2 of 2020, corresponding to the onset of the COVID-19 pandemic, GDP implicit price deflator declined by 0.53%. All of these instances, however, were limited to a single quarter. Thus, experiencing deflation of 1.84% over a three-quarter period would represent an unprecedented catastrophe that is more than three times more significant than what has recently been experienced due to the COVID-19 pandemic. Given the health of the economy in 2021 to date, such an outcome is a near impossibility.

Q. WHAT LEVEL OF INFLATION IS EXPECTED FOR THE REMAINDER OF 2021?

A. We will know more about the economic condition in 2021 as this case progresses. However, the general consensus in the financial press is that, as a result of the easing of the COVID-19 pandemic, prices will increase. Certainly, inflationary expectations have been high in the past few months. Prices of lumber, for example, have experienced record high levels during the first half of 2021.

Further, as of writing this testimony, Q2 2021 is underway. Based on the general health of the economy, it can be observed that catastrophic deflation is not being experienced in Q2 2021. Based on this observation, it can be concluded that the likelihood of catastrophic deflation necessary for the PTC rate to remain at 2.5¢/kWh is even more remote. If one simply

[5/] The historical data is provided in my workpapers.

assumes that the GDP implicit price deflator will remain constant in Q2 of 2021, the level of deflation in Q3 and Q4 necessary for the PTC rate to stay at 2.5¢/kWh is 2.45% on a cumulative basis. Based on this observation and the discussion above, I recommend increasing the PTC rate to 2.6¢/kWh as a known and measurable change in this proceeding.

III. AVERAGE MARKET CAPS

Q. WHAT IS PACIFICORP PROPOSING WITH RESPECT TO MARKET CAPS?

A. PacifiCorp is proposing to modify its Market Cap methodology to be based on the methodology that the Commission rejected in the 2013 TAM, Docket UE 245. Rather than using the Market Cap methodology based on the highest monthly levels of short-term firm market transactions, in the four-year base period, PacifiCorp proposes to use Market Caps based on average levels, consistent with its proposal in the 2012 TAM filing, Docket UE 227. PacifiCorp provides no justification for this change, and the actual data does not support such a change. Moreover, since PacifiCorp is changing its modeling framework from the GRID model to the AUOROA model, there is little need to attempt to modify GRID's modeling parameters at this time. Accordingly, I recommend the Commission reject PacifiCorp's proposal and require PacifiCorp to continue to use the approved methodology.

Q. WHAT ARE MARKET CAPS?

A. The GRID model is a production cost model that uses a linear program to optimize market sales, market purchases, plant dispatch, and transmission, subject to series of cost and operational inputs meant to simulate plant dispatch. Market caps are a particular parameter input into the GRID model that limits the amount of sales or purchases that the model may make at any particular market hub and time period.

Q. HAS THE MARKET CAP METHODOLOGY BEEN LITIGATED IN PAST PROCEEDINGS?

A. Yes. The current Market Cap methodology is the biproduct of many years of litigation. Market caps were originally introduced in the early years of the GRID model, but were limited to graveyard hours for major market hubs, except Mona.[6/]

In Docket UE 227 (the 2012 TAM), however, PacifiCorp made a material change to Market Cap modeling, changing the methodology to be based an average level of short-term firm sales, on a diurnal basis, over the 48-month base period. In that docket, ICNU, AWEC's predecessor, opposed the change to the Market Cap methodology because there are many hours in the historical period when the actual hourly sales amount exceeded the average sales value used in the Market Cap calculation.[7/] In that Docket, the Commission acknowledged ICNU's concerns, while making the following finding:

> We will accept Pacific Power's modeling of Market Caps here on a non-precedential basis. We direct Staff to conduct workshops with the parties to address the market caps issue, with the goal of determining whether agreement can be reached on a fair and reasonable method for modeling (or excluding) market caps in the future. If no agreement can be reached, we will expect Pacific Power to provide clear and robust evidence justifying its modeling of market caps in the company's next TAM proceeding. We will also ask Staff to present in the next TAM docket its own technical analysis of this issue.[8/]

In Docket UE 245 (the 2013 TAM), parties were unable to reach a consensus on the issue surrounding Market Caps, and PacifiCorp filed its case using the average Market Cap methodology. Accordingly, the average Market Cap methodology was again litigated, with ICNU and Staff opposing the use of Market Caps altogether. In resolution, the Commission

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6/ UE 245, Direct Testimony of Gregory N. Duvall, PAC/100, Duvall/19:6-12 (Feb. 29, 2012).

7/ UE 227, Order 11-435 at 21 (Nov. 4, 2011).

8/ Id. at 23.

accepted PacifiCorp's continued use of Market Caps. Notwithstanding, rather than using the arithmetic average over the four-year period, the Commission accepted Staff's alternate position and directed PacifiCorp "to revise GRID to base market caps on the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[9/] This is the methodology that is in place today.

Importantly, in discussing the arguments surrounding the modeling of Market Caps in GRID, the Commission noted that "[b]ecause GRID is a forecasting model that is only as good as its constructs and inputs, the real question presented is not whether market caps should be used as a patch to address certain limitations of the GRID model, but whether the GRID model itself should be fixed."[10/] As discussed below, given PacifiCorp's anticipated replacement of GRID with AURORA, it is not necessary to experiment with fixing GRID at this time.

Q. WHAT IS PACIFICORP PROPOSING IN THIS PROCEEDING?

A. Notwithstanding the extensive litigation discussed above, PacifiCorp is proposing that the Commission reverse its decision in Docket UE 245 (the 2013 TAM), and revert to using average Market Caps.

Q. WHY IS PACIFICORP PROPOSING TO REVERSE THE COMMISSION'S DECISION IN DOCKET UE 245?

A. PacifiCorp witness Webb identified language in the final order in Docket UE 374, its 2020 general rate case, stating that "PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery."[11/] PacifiCorp believes that statements such as

[9/] UE 245, Order 12-409 at 8 (Oct. 29, 2012).
[10/] Id. at 7.
[11/] UE 374, Order No. 20-473 at 130 (Dec. 18, 2020).

this from the Docket UE 374 Order justify its reinstitution of a previously rejected Market Caps method.

PacifiCorp also makes a number of other blanket assertions such as the "original market caps methodology did not use the maximum monthly capacity and PacifiCorp opposed this revision in the 2013 TAM on the basis that it would reduce forecast accuracy,"[12] and statements such as "the maximum monthly capacity of the last four years which makes Market Caps higher, or less restrictive, without regard to whether those caps replicate actual market conditions."[13] These assertions, however, were not supported by analysis.

Q. DID PACIFICORP PERFORM ANY QUANTITATIVE ANALYSIS TO SUPPORT ITS PROPOSAL?

A. No. While PacifiCorp makes blanket assertions about the accuracy of the Market Caps assumption, no quantitative analysis was provided to support those assertions. In contrast, Market Caps are an issue that has been extensively litigated in past proceedings based on thorough quantitative analysis. To the extent that PacifiCorp seeks to reverse the Commission's prior decision, PacifiCorp bears the burden to present evidence supporting the change. In this case, the only evidence PacifiCorp has provided are unsupported, and previously rejected, assertions, without any analytical backing.

Q. IS THE COMMISSION'S DECISION IN DOCKET UE 374 A VALID BASIS TO JUSTIFY A CHANGE TO THE MARKET CAPS METHODOLOGY?

A. No. My understanding is that the Commission must decide this case based on the evidence submitted in this case. To the extent the Commission made a statement in its Order in Docket UE 374 questioning the level of sales forecast in the GRID model, such a finding would have

[12] PAC/100, Webb/10:11-13.
[13] Id. at 11:7-9.

been based on the evidence submitted in that docket and not something that can be relied upon to arrive at a decision in this case.

Q. DO YOU AGREE WITH PACIFICORP'S ASSERTION THAT ITS PROPOSAL REPRESENTS THE ORIGINAL METHODOLOGY?

A. No. As discussed above, the original Market Cap methodology was limited to graveyard hours at major market hubs. The methodology PacifiCorp proposes in this docket was accepted only in the 2012 TAM on a provisional and non-precedential basis. Following further review, the Commission evaluated the merits of the average Market Cap method in the 2013 TAM and explicitly rejected it in favor of Staff's alternative method.

Q. IS THE HYPOTHETICAL EXAMPLE PACIFICORP PROVIDED ABOUT EXTRAORDINARY SALES RELEVANT?

A. PacifiCorp also provides a hypothetical example where sales were extraordinary in March of one year and April of another year.[14/] This example was not based on any actual analysis that PacifiCorp performed, and therefore is not relevant.

Q. HAVE YOU REVIEWED STAFF'S ANALYSIS FROM DOCKET UE 374 ALLEGING THAT OFF-SYSTEM SALES ARE BEING OVER FORECAST?

A. No. It appears that much of PacifiCorp's recommendation relies on an analysis that Staff performed in Docket UE 374. That information has not been provided in this docket. Notwithstanding, it is necessary to point out that performing an analysis of off-system sales between forecast NPC and actual operations can be somewhat difficult. This is primarily because much of the sales that PacifiCorp makes are not reported in actual NPC. A large portion of PacifiCorp's off-system sales are "booked-out," i.e., netted against offsetting purchases and not included in actual NPC. Similarly, the NPC forecast also includes the "day-

[14/] Id. at 11:9-17.

ahead/real-time" ("DA/RT") adjustment, which represents additional balancing transactions in the form of offsetting sales and purchases that are added to net power costs outside of the GRID model. Thus, when preparing a comparison of forecast off-system sales to actual off-system sales, it is necessary to view these netting transactions in a consistent manner.

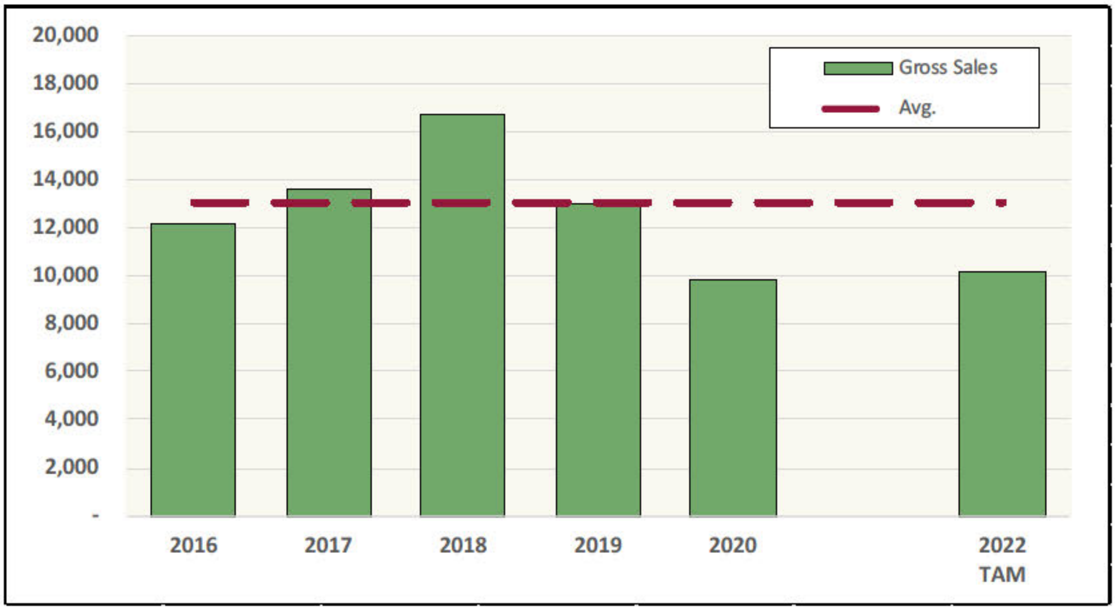
In Docket UE 296, PacifiCorp described the proper way to compare forecast off-system sales to actual off-system sales. When comparing the volumes of off-system sales transactions in forecast NPC, which includes the DA/RT adjustment, it is necessary to compare against the volume of transactions from actual net power costs that also include book-out transactions.[15/] This is because the DA/RT transactions that are added outside of the GRID model are based on total historical volumes "including transactions that may later be booked-out."[16/]

Q. HAVE YOU PERFORMED THAT ANALYSIS?

A. Yes. In Figure 1 below, I perform the same comparison PacifiCorp performed in Docket UE 296, supporting the DA/RT adjustment. The analysis compares the short-term firm sales volumes included in the 2022 NPC forecast, using the currently approved market cap methodology, with the actual volumes over the period 2016 through 2020 with the amount forecast in the current TAM proceeding, including the DA/RT adjustment and the book-outs.

15/ UE 296, Reply Testimony of Brian Dickman, PAC/500, Dickman/25:1-26:16.
16/ Id. at 21:18-19.

Figure 1
Sales Volume Comparison 2016-2020 vs 2022 TAM w/Current Market Cap Method
Including Netting Transactions (GWh)



Q. PLEASE PROVIDE AN OVERVIEW OF FIGURE 1.

A. Figure 1 is a comparison between the volume of sales, in gigawatt-hours, over the period 2016 through 2020 to the volume of sales forecast in the current TAM proceeding. The solid, green portion of the bars represents the volume of gross sales, i.e., including book-outs and the DA/RT adjustment. The book-out amounts are based on the amounts reported in PacifiCorp's FERC Form 1 in the respective years. Finally, the dashed line represents the average of the sales transactions over the period 2016 to 2020.

Consistent with PacifiCorp's analysis in Docket UE 296, this analysis shows the "system balancing volumes in this case are comparable to the historical levels."[17/] In fact, the off-system sales being forecast in the GRID model are less than the historical average, suggesting that the current market cap methodology is too restrictive.

[17/] Id. at 26:15-16.

Q. ARE THERE REASONS TO EXPECT SALES VOLUMES TO BE INCREASING?

A. Yes. As a result of the wind repowering and Energy Vision ("EV") 2020, PacifiCorp is producing a large volume of additional generation that it will be to able market, which was not available in the historical period. The EV 2020 resources alone produce approximately 5,300 GWh of additional generation, and all other things being equal, that new generation is a reason to expect a material increase to sales volumes relative to historical averages. This increase in sales volumes is not necessarily being borne out in the sales data detailed in Figure 1, above. Thus, PacifiCorp's current Market Cap methodology already represents a moderate level of sales relative to what is expected with the addition of the EV 2020 and repowering resources, which its proposed change to this method would further reduce.

Q. HAS PACIFICORP EVER PERFORMED AN ANALYSIS TO VALIDATE WHETHER THE GRID MODEL PRODUCES AN ACCURATE FORECAST INCLUDING THE EXISTING MARKET CAP METHODOLOGY?

A. Yes. In Docket UE 339, PacifiCorp performed a backcast using actual data from 2016, which included the use of the existing Market Cap methodology. As a result of that analysis, PacifiCorp concluded that "when actual data is used as inputs, GRID is able to produce the 2016 NPC within a very reasonable range compared to actual 2016 NPC."[18/] In the study, "[t]he GRID model estimated total company 2016 NPC to be $1,466.3 million compared to actual costs of $1,465.9 million, a variance of $0.4 million or 0.03 percent."[19/] Consequently, while PacifiCorp has repeatedly asserted that the GRID model under-forecasts its power costs, any under-recovery PacifiCorp has incurred in recent years does not appear to be due to

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18/ UE 339, PAC/100, Wilding/25:20-22.
19/ Id. at 19:21-23.

modeling, but to real-world impacts that were not forecasted, such as the Enbridge outage. The power cost adjustment mechanism exists to address these types of impacts.

Fundamentally, PacifiCorp has not demonstrated in this case that there is a problem with the GRID model that warrants changing the Market Cap methodology. The goal of a forecast is not necessarily to perfectly emulate every aspect of net power costs viewed in isolation. The goal of the forecast is to arrive at a reasonable level of overall costs to include in rates. Market caps are one element in the overall power cost forecast, and if the overall forecast is reasonable, there is no justification to make a change to individual assumptions such as Market Caps.

Q. IS PACIFICORP PLANNING TO REPLACE THE GRID MODEL?

A. Yes. PacifiCorp is in the process of implementing the AURORA model for ratemaking. PacifiCorp had indicated that it would use the Aurora model for this TAM filing, but was unable to complete the modeling in time for the filing. Despite this delay, it is now certain that PacifiCorp will use AURORA to model power costs in next year's TAM, as the Company has recently filed a "power cost only rate case" in Washington that transitions from GRID to AURORA.[20/]

Through its Market Caps proposal, PacifiCorp is requiring a major change in the way GRID modeling is being performed, but the change will be moot once the new AURORA model is implemented next year. As noted above, with respect to Market Cap modeling inputs, the Commission has previously commented that "the real question is not whether market caps should be used as a patch to address certain limitations of the GRID model, but whether the

[20/] Washington Utilities & Transp. Docket No. UE-210402.

GRID model itself should be fixed."[21/] Given the impending replacement of the GRID model, making a dramatic change to precedent, only for the change to be superseded the next year, is neither desirable nor an efficient use of the Commission's resources.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend the Commission reject PacifiCorp's proposal to use the average Market Cap methodology that the Commission previously rejected in the 2013 TAM. PacifiCorp's only justification for changing the methodology are vague references to the Commission's order in Docket UE 374. PacifiCorp provides no concrete analysis or justification to make such a change in this proceeding and relying on obscure references to analyses performed by another party in another proceeding by no means meets the burden of proof to justify such a significant rate increase on ratepayers. To the contrary, the actual data shows that the GRID model is not over-forecasting sales. PacifiCorp recently concluded that the GRID model configured with the current Market Cap methodology produces an accurate forecast in the backcast analysis performed in Docket UE 339. Further, such a change is not timely, as PacifiCorp will be moving to a new model shortly.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of rejecting PacifiCorp's proposal is a $19,747,145 system, or $5,229,355 Oregon-allocated, adjustment to NPC.

[21/] Docket No. 245, Order 12-409 at 7.

IV. OTHER REVENUES

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO OTHER REVENUES?

A. I have two recommendations related to Other Revenues. First, PacifiCorp omitted the calculation of Other Revenues from this case and refused to provide the analysis in discovery. I recommend including an Other Revenues forecast in TAM revenues, consistent with past TAM filings. Second, I have observed that PacifiCorp has experienced a material increase in fly ash sales in recent years. Accordingly, I recommend that Fly Ash Sales also be considered in the Other Revenues calculation. These recommendations reduce TAM revenues by $949,615 on an Oregon-allocated basis.

Q. HOW ARE OTHER REVENUES CONSIDERED IN PACIFICORP'S TAM FILINGS?

A. In Docket UE 216, PacifiCorp stipulated to, and the Commission approved, a requirement to include an adjustment for Other Revenues in stand-alone TAM filings.[22/] The stipulation stated "[i]n future stand-alone TAM filings, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC."[23/] In a general rate case year, PacifiCorp updates Other Revenues in the context of the overall revenue requirement, and no Other Revenue adjustment is made in the TAM. PacifiCorp did not, for example, make an adjustment for Other Revenue in the 2020 TAM because Other Revenues were updated in PacifiCorp's GRC filing in Docket UE 374. Notwithstanding, when preparing this case, PacifiCorp did not reintroduce the adjustment in this year's stand-alone TAM filing.

22/ UE 216, Stipulation ¶ 9 (July 6, 2010).
23/ Id.

Q. DID YOU REQUEST PACIFICORP TO PROVIDE THE CALCULATION OF THE OTHER REVENUE ADJUSTMENT?

A. Yes. In AWEC Data Request No. 16(b), PacifiCorp was asked to provide an updated calculation of Other Revenues, consistent with the Commission Order in Docket UE 216. PacifiCorp, however, refused to perform the analysis, stating that "[b]ecause the forecasted revenues for 2022 are not expected to change from Other Revenues included in the Company's general rate case (GRC), Docket UE 374, the Company has not requested any adjustment related to Other Revenues in the 2022 TAM." Strangely, while not identified in the text of the response, PacifiCorp did provide an attachment to its response which appears to have attempted to update the Other Revenue Calculation, showing that the Other Revenue value was expected to change in 2022.

Q. DO YOU AGREE THAT THE COMPANY HAS THE OPTION TO DECIDE WHETHER TO REQUEST AN OTHER REVENUE ADJUSTMENT?

A. No. My understanding is that PacifiCorp does not have the authority to unilaterally change the effect of a prior Commission order. Accordingly, including the Other Revenue adjustment is not at the Company's discretion, but an affirmative requirement of its TAM filings.

Q. IS IT POSSIBLE THAT THE OTHER REVENUE AMOUNTS ARE NOT CHANGING?

A. No. Because the allocation factors are changing, it would be impossible from a mathematical perspective for the Other Revenue amounts to not change at all. Even if the system revenues remain the same, the Oregon-allocated revenues will change. Further, if PacifiCorp believes the amounts are not changing, PacifiCorp is still required to present the analysis to demonstrate so, consistent with the requirement from Docket UE 216.

Q. DID YOU ATTEMPT TO REVIEW THE OTHER REVENUE ITEMS INCLUDED IN THE UE 374 FORECAST?

A. Yes. In response to AWEC Data Request 16(c), PacifiCorp confirmed that "[t]he wind-based ancillary service revenues on a Total Company basis included in base rates is $10,024,343. Allocated on the approved system generation (SG) allocation factor at 26.023 percent, Oregon's share of this amount is $2,608,598." Based on the revenue requirement workpapers from Docket UE 374, the primary source of Other Revenues was from a contract with Seattle City Light for the Stateline wind farm. In AWEC Data Request 16(e), AWEC requested that PacifiCorp provide a copy of the Seattle City Light - Stateline contract. With no explanation, PacifiCorp responded that no such contract exists.

Q. WHAT DO YOU RECOMMEND?

A. Given PacifiCorp's unwillingness to provide a forecast for Other Revenues and the fact that PacifiCorp was unable to produce any agreement associated with the Seattle City Light - Stateline revenues, I recommend using the revenue forecast from the attachment provided in response to AWEC Data Request 16. Notwithstanding, I updated the revenue amount included in base rates to be consistent with the amounts that PacifiCorp reported in response to AWEC Data Request 16(c).

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS RELATED TO THE OTHER REVENUE FORECAST?

A. Yes. Upon review of PacifiCorp's FERC Form 1, it is apparent that PacifiCorp has experienced a material increase to revenues associated with fly ash sales relative to the amounts included in base rates. These sales are directly tied to the production at PacifiCorp's coal plants, primarily Jim Bridger, so I recommend that they also be considered in the Other Revenue forecast.

Q. WHAT IS FLY ASH?

A. Fly ash is a byproduct of the combustion of coal. It is used in construction to develop concrete, bricks and other building supply products.

Q. WHAT AMOUNT OF REVENUES DOES PACIFICORP EARN FROM SELLING FLY ASH?

A. In 2020 PacifiCorp recognized $6,851,586 of fly ash sales, with approximately $1,814,408 allocated to Oregon. This represents a material increase from the $4,256,000 of fly ash sales, or $1,108,000 Oregon-allocated, considered in Docket UE 374.

Q. FROM WHAT COAL PLANTS DOES PACIFICORP SELL FLY ASH?

A. In response to AWEC Data Request 17, PacifiCorp identified the sources of its fly ash sales for calendar year 2020. PacifiCorp responded that the fly ash sales are predominantly from the Jim Bridger power plant, with small amounts being sold from the Naughton, Craig and Cholla plants.

Q. HOW DO YOU PROPOSE TO DEVELOP A FORECAST FOR FLY ASH SALES?

A. I recommend using calendar year 2020 as the basis for the forecast in this proceeding, adjusted for known and measurable changes. In addition, I propose to adjust the 2020 amount for retirement of Cholla, removing all fly ash sales from Cholla included in the historical data. This is consistent with the way that wheeling expenses are forecast.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Based on the proposal above, I have performed an updated Other Revenue calculation—including a provision for fly ash sales—which may be found in Exhibit AWEC/104. As can be seen, the effect of these recommendations is a $949,615 reduction to Oregon-allocated TAM revenues.

V. BRIDGER COAL COMPANY MATERIALS AND SUPPLIES

Q. PLEASE DESCRIBE THE ANALYSIS THAT YOU PERFORMED WITH RESPECT TO BRIDGER COAL COMPANY MATERIALS AND SUPPLIES EXPENSES.

A. In Confidential Exhibit AWEC/105, I have performed an analysis evaluating the accuracy of PacifiCorp's forecast of materials and supplies expenses at Bridger Coal Company ("BCC"). The analysis reviews the BCC forecast prepared in the final TAM update filings in Dockets UE 232 (2018 TAM), UE 339 (2019 TAM) and UE 356 (2020 TAM). PacifiCorp provided the BCC forecasts for these respective TAM filings in response to AWEC Data Request 20. The analysis compares the forecasted materials and supplies expenses in each of these dockets to the materials and supplies expenses incurred in actual operations. The actual operating results of BCC was provided in response to AWEC Data Request 04. Based on the comparison, it is possible to evaluate how accurate the prior forecasts have been. This is an important consideration because these forecast levels are based on subjective judgements, rather than a predetermined methodology.

Q. WHAT DID YOU FIND?

A. Based on the analysis, I determined that PacifiCorp's prior forecasts for materials and supplies expenses at BCC were grossly overstated in every year analyzed. In 2020, for example, the forecast was overstated by 32%.

Q. WHAT DO YOU RECOMMEND?

A. Given the consistent history of over-estimating materials and supplies expenses as well as the magnitude of the overstatement, I recommend an adjustment based the historical variances identified in Confidential AWEC/105. As can be seen, my analysis applies the average historical percent variances, measured on a dollars-per-ton basis, to the forecast materials and supplies expenses for the test period. The result is used to develop an adjustment to the test period forecast.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. This recommendation produces a $3,096,823 reduction to PacifiCorp allocated coal costs. On an Oregon-allocated basis, this adjustment amounts to a $785,644 reduction to NPC.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

PUBLIC UTILITY COMMISSION OF OREGON

UE 420

PACIFICORP

PAC/1302

Docket No. UE 390 AWEC/200
Rebuttal and Cross-Answering Testimony of Bradley G. Mullins
(redacted version)

September 1, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp d/b/a Pacific Power	)
	)
2022 Transition Adjustment Mechanism	)
	)

REBUTTAL AND CROSS-ANSWERING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

July 30, 2021

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AWEC/204 – Revised Other Revenue Adjustment, Including Coal Ash Sales

AWEC/205 – Portland General Electric Company Negative Opt-Out Charges From 2008

I. INTRODUCTION AND SUMMARY

Q. ARE YOU THE SAME WITNESS WHO PREVIOUSLY FILED OPENING TESTIMONY ON BEHALF OF AWEC IN THIS DOCKET?

A. Yes. I previously filed Opening Testimony on behalf of the Alliance of Western Energy Consumers ("AWEC") regarding PacifiCorp's proposed Transition Adjustment Mechanism ("TAM") revenues, including Net Power Costs ("NPC"), for calendar year 2022.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Reply Testimony of PacifiCorp witnesses Staples and Ralston regarding the NPC issues raised in my Opening Testimony. I also respond to PacifiCorp witness Meredith regarding the Consumer Opt-Out Charge.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY

A. My recommendations are summarized in Table 1, below, followed by brief descriptions of each issue.

Table 1-REB
AWEC Proposed TAM Adjustments
($000)

		Primary Recommendation	Alternative Market Cap Method
1	**Rebuttal Filing**	**1,712,670**	**1,712,670**
2	Adjustments		
5	Market Caps	(7,027,724)	(1,510,044)
6	Other Revenues	(929,973)	(929,973)
7	BCC Materials & Supplies	(1,175,112)	(1,175,112)
8	**Total Adjustments**	**(9,132,809)**	**(3,615,128)**
9	**Adjusted**	**(7,420,139)**	**(1,902,458)**

Production Tax Credit Rate: PacifiCorp accepted my recommendation to update the production tax credit rate for 2022 to 2.6¢/kWh in its Rebuttal Filing. I maintain this recommendation in the present testimony.

Market Caps: I continue to recommend maintaining the currently approved methodology for Market Caps. If the Commission does decide to change the methodology, I also offer an alternative recommendation that ties off-system sales directly to the historical average.

Bridger Coal Company Materials & Supplies: I continue to recommend an adjustment for the materials and supplies forecast at Bridger Coal Company. PacifiCorp has not offered any explanation as to why the historical over-forecasting, which PacifiCorp did not dispute, was reasonable and not recurring.

Other Revenues: I continue to recommend fly ash sales be considered in the other revenue forecast.

Consumer Opt-Out Charge: I recommend that Calpine's recommendation regarding the Consumer Opt-Out Charge be adopted.

II. PRODUCTION TAX CREDIT RATE

Q. DID PACIFICORP ACCEPT YOUR RECOMMENDATION TO INCREASE THE PRODUCTION TAX CREDIT RATE TO 2.6¢/KWH?

A. Yes. [1/] This recommendation reduces TAM revenues by $2,649,684.

III. AVERAGE MARKET CAPS

Q. PLEASE SUMMARIZE THE RECOMMENDATION YOU MADE REGARDING THE MODELING OF MARKET CAPS IN OPENING TESTIMONY?

A. In Opening Testimony, PacifiCorp proposed modifying its Market Cap methodology to be based on the methodology that the Commission rejected in the 2013 TAM, Docket No. UE 245. Rather than using the Market Cap methodology based on the highest monthly average of short-term firm market transactions, in the four-year base period, PacifiCorp proposed using the four-year average, consistent with its proposal in the 2012 TAM filing, Docket No. UE 227. PacifiCorp claimed that the Commission-approved method results in an over-estimation of sales. While PacifiCorp provided no evidence to support its change in Direct Testimony

[1/] PAC/400, Staples/5:14-17.

other than a reference to the Commission's final order in Docket No. UE 374, PacifiCorp has provided new information and analysis in Reply Testimony. In Opening Testimony, I recommended the Commission reject PacifiCorp's proposal. In this testimony, I demonstrate that the Commission-approved methodology produces overall wholesale sales levels that are in line with historical data, and accordingly, continue to recommend the Commission reject PacifiCorp's proposal. Notwithstanding, if an adjustment is to be made, I recommend the adjustment be targeted to specific markets based on an alternative methodology that I discuss below.

Q. HOW DID PACIFICORP RESPOND TO YOUR OPENING TESTIMONY?

A. PacifiCorp continues to argue that a methodological change is warranted because it has under-recovered NPC in the past.[2/] PacifiCorp also claims that the wholesale market sales forecast in the GRID model exceeds historical actual wholesale market sales,[3/] although it uses an inconsistent analysis to support its claim. Finally, PacifiCorp argues that increased penetration of renewable resources in its portfolio increases the disparity between expected and actual off-system sales.[4/] PacifiCorp does not develop this final argument.

Q. DO YOU AGREE THAT PACIFICORP IS PERSISTENTLY UNDER-RECOVERING IN OREGON?

A. No. The power cost adjustment framework in Oregon, including both the TAM and the Power Cost Adjustment Mechanism ("PCAM"), was carefully designed with the objective of preventing PacifiCorp from under-recovering its overall costs. That is why the Commission imposed an earnings test in the PCAM.[5/] In 2019, for example, PacifiCorp earned a 9.34%

2/ PAC/400, Staples/20:9-10.
3/ PAC/400, Staples/18:8-9.
4/ PAC/400, Staples/20:13-15.
5/ Docket No. UE 246, Order No. 12-493 at 14-15 (Dec. 20, 2012).

Return on Equity, even though its actual NPC was approximately $200,000,000 higher than the TAM forecast. Thus, when arguing that it has under-recovered NPC, PacifiCorp is ignoring the fact that, when viewed on a holistic basis, it has been fully recovering all of its costs and earning a reasonable rate of return in every year of recent history.

Further, the GRID model is designed to produce a normalized forecast of NPC, which does not consider the extraordinary events that have taken place in recent years. In late 2018 and early 2019, for example, there was a pipeline rupture on the Enbridge West Coast pipeline that precipitated an energy crisis that would have been impossible to foresee in the context of a TAM forecast. Similarly, in 2020 the West experienced high market prices as a result of wildfires in Oregon and California.

Q. IS THE AURORA MODEL RELEVANT TO THE USE OF MARKET CAPS IN THIS PROCEEDING?

A. Yes. PacifiCorp has indicated that it will be transitioning to AURORA as its nodal pricing model pursuant to the terms of the 2020 Protocol.

PacifiCorp, however, did not to implement the AURORA model in this proceeding, despite using it just two months later in a filing in Washington.[6] The AURORA model contains a more sophisticated commitment and dispatch logic than the GRID model, which better mimics the actual operation of PacifiCorp's gas plants. At a minimum, any changes made in this proceeding would be premised on the modeling logic used by the GRID model and would not set any expectations for use with, or precedent applicable to, the AURORA model. Thus, while PacifiCorp argues that a simple, straightforward fix is required in this proceeding, the purported effect of the change is transient, as it will later be supplanted with an

[6] See Washington Utilities and Transportation Commission Docket No. UE-210402, PacifiCorp 2022 Power Cost Only Rate Case (June 1, 2021).

entirely new model. This is like spending money to put new tires on an old car, which one anticipates donating to charity.

Rather than performing a comprehensive rework of the GRID model in this docket today, it would be more fruitful, knowing that the GRID model will be imminently replaced, to maintain the status quo and wait until the AURORA model is implemented to resolve such controversial modeling issues.

It is possible that the AURORA model will have the same limitations as the GRID model, however it is also possible that it may not. Until the model is presented and the parties are given the opportunity to investigate the model, it is impossible to know whether any analysis adopted in this proceeding will be relevant going forward or otherwise resolved through the new model logic. Given that PacifiCorp did not implement the AURORA model in this docket, however, it is inappropriate to make controversial modeling changes to the GRID model that might otherwise be resolved in the AURORA model.

Q. DID PACIFICORP PRESENT ANY ANALYSIS DEMONSTRATING THAT INCREASED PENETRATION OF RENEWABLE RESOURCES IN PACIFICORP'S PORTFOLIO HAS INCREASED THE DISPARITY BETWEEN EXPECTED AND ACTUAL OFF SYSTEM SALES?

A. No. This was a concerning statement, however. PacifiCorp has justified large volumes of new renewable resources based on its ability to make off-system sales. If those expected off-system sales cannot be realized in actual operations, then it calls into question the efficacy of not just this TAM modeling but also the Integrated Resource Plan modeling supporting these new resource additions.

Q. DID PACIFICORP PERFORM ANY NEW ANALYSIS TO SUPPORT ITS PROPOSAL TO REVERT BACK TO AVERAGE MARKET CAPS?

A. Yes, however the new analyses are either irrelevant or inaccurate.

For example, in Exhibit PAC/400, Staples/23, Figure 3, PacifiCorp presents a numerical example that is intended to show that the use of a maximum average value for Market Caps results in over-forecasting wholesale market sales. That analysis, however, was based on made-up numbers that have no bearing on the actual sales that PacifiCorp has made in the past, nor are they used in the Market Cap calculation. Additionally, the analysis is based on six time periods, rather than the four time periods used in the Market Cap calculation.

Further, the mathematical conclusion PacifiCorp reaches from the numerical example is irrelevant to the issue at hand with respect to Market Caps. The only fact that may be ascertained from PacifiCorp's numerical example is that the maximum of a set of numbers exceeds the average of the same set of numbers. This mathematical conclusion, however, does not implicate the Market Cap methodology. Market Caps in the GRID model function as the maximum amount of sales that can be made in a particular time period at a particular market hub, not the average. The GRID model does not transact at the maximum amount assumed in the Market Cap calculation in every hour. While the GRID model can transact up to the level assumed in the Market Cap calculation, the GRID model transacts at less than the Market Cap value in many hours, and is making sales in some hours. Thus, the fact that a maximum value is being used for Market Caps does not necessarily demonstrate whether the GRID model will ultimately produce sales at, above, or below, the historical average.

Q. HAVE YOU PERFORMED A SIMILAR ANALYSIS USING ACTUAL DATA?

A. Yes. Table 2-REB, below, provides a concrete example, using actual data from the GRID model, showing that the use of a maximum value for Market Caps does not necessarily result in GRID model sales exceeding the historical average.

CONFIDENTIAL TABLE 2-REB
Mona Market Cap Calculation
Average of Average v. Max Average
February 2022 aMW

[redacted]

Table 2-REB details the actual Heavy-Load-Hour ("HLH") and Light-Load-Hour ("LLH") Market Cap calculation for the Mona market for May 2022 of the test period. The calculation is performed using actual wholesale sales in four periods: May 2017, May 2018, May 2019, and May 2020. Under the Commission-approved method, the Market Cap is calculated as the maximum of these four values, labeled "Max Average." In the row titled "GRID (Commission)", the actual GRID model sales using the Commission-approved Market Cap calculation are detailed. As can be seen, the GRID model does not transact up to the maximum value in every hour, and accordingly, the resulting sales value is ultimately less than (or approximately equal to) the average of the four values used to calculate the Market Cap.

Similarly, if using the average value as the Market Cap value, as PacifiCorp proposes, the GRID model will inherently transact less than the average amount. This is due to the fact that the GRID model sometimes transacts at lower levels than, but never exceeds, the historical average. Thus, demonstrating that the maximum always exceeds the average does not necessarily indicate that using a market cap value based on the maximum average value will result in GRID model sales that are more than the average value. By using the maximum value, however, it is possible that the GRID model could forecast a volume of transactions that exceeds the historical value depending on the distribution of sales levels at a particular market.

Q. HAVE YOU PERFORMED A SIMILAR ANALYSIS FOR OTHER MARKETS?

A. Yes. In Exhibit AWEC/201, I have performed an analysis of the market cap calculation for each market and each time period to determine the extent that using the maximum average value produces a GRID model result that exceeds the average value. The result of that analysis is presented in Table 3-REB, below:

Table 3-REB
GRID Model Sales Variance from Four-Year Historical Average

	PacifiCorp Proposed				Commission Approved			
	COB	4C	Mona	Mead	COB	4C	Mona	Mead
Jan	-0%	-15%	-29%	-24%	84%	9%	-17%	-25%
Feb	-31%	-26%	-41%	-28%	21%	-6%	-32%	-23%
Mar	-34%	-35%	-51%	-24%	-4%	-7%	-8%	21%
Apr	-29%	-26%	-50%	-47%	-14%	1%	-27%	-15%
May	-25%	-51%	-60%	-77%	33%	-25%	-41%	-70%
Jun	-20%	-7%	-9%	-49%	20%	33%	51%	-46%
Jul	-31%	-4%	-4%	-20%	43%	62%	115%	-4%
Aug	-33%	-2%	-8%	-7%	27%	45%	50%	36%
Sep	-13%	-2%	-1%	-17%	69%	27%	30%	-12%
Oct	0%	-2%	-27%	-39%	38%	45%	-14%	-36%
Nov	-0%	-4%	-36%	-49%	44%	12%	-22%	-54%
Dec	-6%	-25%	-52%	-56%	64%	-11%	-41%	-61%
Average	-19%	-17%	-31%	-36%	36%	15%	4%	-24%

As can be seen from the table, PacifiCorp's methodology produces GRID model sales values that are always below the four-year historical average of actual sales and by a significant margin. In contrast, the Commission-approved method produces results that are sometimes below and other times above the four-year historical average. In the Commission-approved method, the sales from the California Oregon Border ("COB") market produce the largest positive variances, whereas the Mead Market produces the largest negative variances. I discuss some methods to address the variances associated with the Commission-approved method below. First however, it is necessary to discuss the errors in the analysis of historical sales that PacifiCorp performed.

Q. WHAT ANALYSIS DID PACIFICORP PERFORM WITH RESPECT TO HISTORICAL WHOLESALE SALES VOLUMES?

A. In the second Figure 3 in Exhibit PAC/400, Staples/23, PacifiCorp presents a comparison between the sales volumes reported in the Actual NPC Report with the amounts reported the GRID NPC report over the period 2012 through 2020.[7/] Further, in Figure 4 in Exhibit PAC/400, Staples/24, PacifiCorp performs a similar analysis based upon sales revenues.

Q. DO YOU AGREE WITH PACIFICORP'S ANALYSIS OF HISTORICAL SALES?

A. No. PacifiCorp's comparison between the sales volumes reported in the Actual NPC Report and the GRID NPC report is inaccurate and invalid. The sales reported in the Actual NPC report are in no way comparable to the sales reported in the GRID NPC report. This is critically important. The reason for this is, for accounting purposes, the sales included in the Actual NPC report are adjusted for transactions which have been booked-out.

Q. WHAT ARE BOOK-OUTS?

A. In its FERC Form 1 accounting, PacifiCorp makes an adjustment to reverse certain off-setting purchase and sale transactions, which are for the same delivery period and at the same location.

[7/] Note that at Exhibit PAC/400, Staples/23, the figures related to historical wholesale sales are misnumbered.

This netting adjustment is referred to as a book-out adjustment. PacifiCorp still earns revenues and benefits from the underlying offsetting transactions and the transactions are still reported in Sales for Resale in FERC Account 447. The revenues from the underlying offsetting transactions, however, are deducted from Account 447, as a separate adjustment, and netted against purchases. This book-out adjustment can be found on pages 310.8-311.8 of PacifiCorp's 2020 FERC Form 1, an excerpt from which is detailed in Figure 1 below.

Figure 1-REB
Book-out Adjustment to Wholesale Sales in 2020 FERC Form 1

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	MegaWatt Hours Sold (g)	REVENUE Other Charges ($) (j)
8	Netting - Bookouts	-4,947,283	-134,256,359

Thus, while PacifiCorp made 9,833,194 MWh of wholesale sales, corresponding to wholesale sales revenues of $309,000,337,[8/] the total amount of sales reported in its Actual NPC was reduced for the book-out adjustment identified in Figure 1-REB. Accordingly, in the Actual NPC report, PacifiCorp only reported 4,885,911 MWh of sales, and corresponding sales revenues of $173,806,881.[9/] The book-out adjustment in Actual NPC represents over half of the sales that PacifiCorp made in 2020 and therefore cannot be ignored when forming comparisons between the GRID model results and Actual NPC.

Q. DOES THE GRID MODEL INCLUDE BOOKED-OUT TRANSACTIONS?

A. Yes. The GRID NPC report includes transaction volumes which would otherwise be booked-out in the adjustment identified in Figure 1-REB and not reported in the Actual NPC report.

8/ Excluding Long-term sales. See Exhibit AWEC/202 for the underlying data.
9/ Representing the 9,833,194 MWh of wholesale sales and $309,000,337 of wholesale revenues reported in Actual NPC, less the amounts detailed in Figure 1-REB.

These book-out transactions in the GRID model NPC report include both the imputed offsetting volumes associated with the DA/RT adjustment, as well as sales volumes associated with an exchange transaction with Public Service Company of Colorado ("PSCo"). Because the PacifiCorp analysis did not make an adjustment to consider these items in a consistent manner, the result is an invalid comparison.

Q. HOW DID PACIFICORP RESPOND TO THE HISTORICAL ANALYSIS OF SALES TRANSACTIONS YOU PRESENTED IN OPENING TESTIMONY?

A. In Opening Testimony, I presented an analysis comparing actual wholesale sales over the period 2016-2020 to the amounts forecast in GRID in this Docket using the Commission-approved Market Cap methodology. When performing the analysis, I made an adjustment to the sales reported in the Actual NPC report to account for book-out transactions in order to produce an analysis that is consistent with the GRID model NPC report. My analysis demonstrated that off-system sales being forecast in the GRID model are less than the historical average, suggesting that the current market cap methodology is too restrictive.[10/]

PacifiCorp did not dispute the results of my analysis. Instead, PacifiCorp argued, incorrectly, that "GRID does not simulate offsetting purchases and sales at a single location in any hour, so booked out volumes do not belong in a discussion of the comparison between GRID's forecasted market activities and actual purchases and sales."[11/] Given the magnitude of the book-out adjustment included in Actual NPC identified above, this statement represents a misunderstanding of the relationship between the GRID model NPC Report and the Actual NPC report.

10/ AWEC/100, Mullins/14.
11/ PAC/400, Staples/25:15-18.

Q. IS IT TRUE THAT "GRID DOES NOT SIMULATE OFFSETTING PURCHASES AND SALES"[12/]?

A. No. PacifiCorp states that the GRID model does not simulate offsetting purchases and sales.[13/] This statement, however, is far from truth. As noted, the GRID NPC report includes volumes associated with the DA/RT adjustment, as well as sales volumes associated with the PSCo exchange, both of which are booked-out in the Actual NPC report. Therefore, treating these items as a book-out in Actual NPC, but not in the GRID model NPC report, results in an inconsistent and invalid comparison.

Q. PLEASE DISCUSS WHY THE DA/RT ADJUSTMENT IS REPRESENTATIVE OF BOOK-OUT TRANSACTIONS?

A. PacifiCorp's Rebuttal NPC includes [redacted] MWh of additional sales volumes and $[redacted] of additional sales revenues associated with the DA/RT adjustment. The DA/RT adjustment was implemented in Docket No. UE 296 as a component of the GRID modeling specifically to address the impact of offsetting purchase and sales transactions, which are being booked-out in the Actual NPC report. PacifiCorp described the DA/RT volumes as follows:

> As designed, the GRID model perfectly balances each hour to the fraction of a megawatt and does not simulate transacting in the market for standard products. The result of the Company's [DA/RT] adjustment is to include additional monthly, daily, and hourly transactions, in the form of offsetting sales and purchases representing this balancing process.[14/]

In PacifiCorp's Opening Brief in Docket No. UE 296, PacifiCorp, in no ambiguous terms, emphasized the need for consistent treatment of book-out transactions and the DA/RT volumes when forming comparisons between the Actual NPC report and the GRID NPC report:

[12/] PAC/400, Staples/25:15-16.
[13/] Id.
[14/] Docket No. UE 296, PAC/500, Dickman/15:5-9.

> Comparisons between transaction levels in actual and forecast NPC must include or exclude book-out transactions on both sides to avoid apples-to-oranges comparisons. Here, the Company demonstrated that its modeled volumes, including the additional [DA/RT] system balancing transactions that are proxies for bookouts, correspond to historical transaction volumes including bookouts.[15]

As PacifiCorp explained, the DA/RT volumes are proxies for book-outs, and therefore, need to be considered in a consistent manner as book-outs. I am not opposing the DA/RT adjustment in this proceeding, and therefore, have accepted PacifiCorp's representation that the DA/RT volumes are the same as book-out transactions. If they are not, however, then the simple solution to addressing the alleged over-forecasting of market sales would be to eliminate the DA/RT adjustment, and the associated incremental sales volumes, altogether.

When I performed the analysis of historical transactions in Opening Testimony, I used the same analysis that PacifiCorp performed in Docket No. UE 296 to support the DA/RT adjustment, including book-out transactions on both sides of the analysis. As I discuss below, however, one could perform an alternative analysis by excluding book-outs from both sides, which also yields similar results to the analysis that I presented in Opening Testimony. Either way, the analysis shows that the overall sales volumes forecast using the Commission approved method is in line with the historical volumes.

Q. PLEASE DISCUSS WHY THE PSCO EXCHANGE AGREEMENT RESULTS IN BOOK-OUT VOLUMES IN GRID.

A. The PSCo Exchange Agreement is a unique transaction that results in large volumes of booked-out transactions at the Palo Verde Market. Under the PSCo Exchange Agreement, PacifiCorp delivers [redacted] MW of energy to PSCo at the Craig power plant in Colorado. In exchange, PSCo returns [redacted] MW of power at the Palo Verde Market back to PacifiCorp. In

[15] Docket No. UE 296, PacifiCorp Opening Brief, at 17:14-18 (Sep. 14, 2015) (internal citations omitted).

GRID, the PSCo Exchange Agreement is modeled as a [redacted] MW sale at the Craig power plant and a corresponding [redacted] MW purchase at Palo Verde. PacifiCorp pays $5,400,000 per year to PSCo in connection with this exchange agreement, which is scheduled to expire at the end of October 2022 in the test period.

Notwithstanding the agreement to receive power at the Palo Verde market, PacifiCorp does not maintain any long-term transmission rights from the Palo Verde market to any other part of its system. Accordingly, all power delivered by PSCo to the Palo Verde market must be subsequently remarketed at the Palo Verde market in the same hours that it is received. The consequence of remarketing the power at the same location and same point in time is that a large volume of sales transactions at the Palo Verde market ends up being included in the book-out adjustment and removed from the wholesale sales reported in Actual NPC. Notwithstanding, the Palo Verde sales attributable to the PSCo exchange return are still included in GRID as a wholesale sale, and therefore, need to be removed when forming a comparison back to Actual NPC.

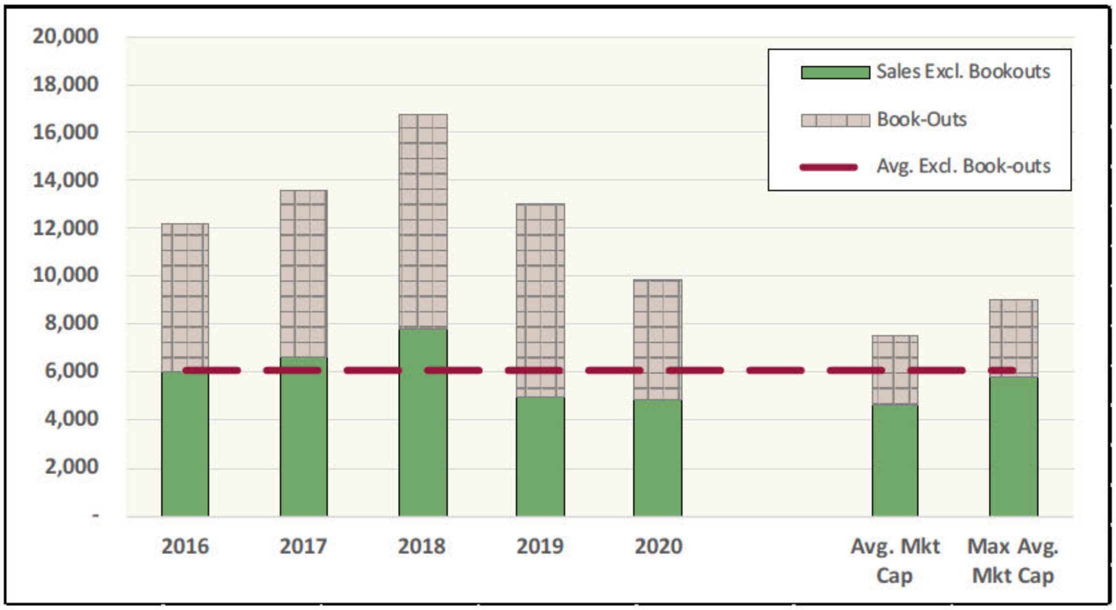
In fact, virtually all sales at the Palo Verde market in the test period are attributable to the resale of power returned under PSCo Exchange Agreement. PacifiCorp has historically held [redacted] MW of long-term transmission rights to the Palo Verde market. These transmission rights, however, expired at the end of 2020, corresponding to the retirement of Cholla 4. As a result of the Cholla 4 retirement, PacifiCorp no longer has any meaningful transmission rights to, or from, the Palo Verde market. Accordingly, the PSCo Exchange Agreement volumes are the only volumes capable of being sold Palo Verde, other than some immaterial short term firm transmission purchases. In the GRID model there are approximately [redacted] MWh in sales at the Palo Verde market in 2022 attributable to the PSCo Exchange Agreement return, which will be booked-out in the Actual NPC report.

These PSCo Exchange Agreement resales can be noted plainly in the GRID NPC Report. At PAC/402, Staples/1, PacifiCorp reports $71,631,443 of sales at Palo Verde even though it has no long-term transmission to access the Palo Verde market. After the PSCo Exchange Agreement expires in November 2022, however, the Palo Verde sales decline to nearly zero, corresponding to some minor amounts of non-firm transmission modeled in GRID.

Q. HAVE YOU PREPARED AN UPDATED VERSION OF THE COMPARISON TO ACTUAL NPC WITH BOOK OUTS EXCLUDED FROM BOTH SIDES?

A. Yes. In Exhibit AWEC/202, I perform an analysis of historical sales included in the actual NPC report, with an adjustment removing booked-out transactions, to the level of sales forecast by GRID in this docket, with a similar adjustment removing booked-out transactions. I performed this comparison based on the GRID model output using both the Commission-approved Market Cap methodology and PacifiCorp's proposed Market Cap methodology. It shows that, if book-outs are considered in a consistent manner, the Commission-approved methodology, using the maximum average value, produces a level of sales volumes that are consistent with the historical average, and that PacifiCorp's proposed method under-forecasts sales relative to the historical average. This analysis has been summarized in Figure 2-REB, below.

Figure 2-REB
Comparison to Historical Sales Volumes Excluding Book-outs



The above figure is identical to the one presented in my Opening Testimony, with the exception that I have deducted book-outs from both the historical Actual NPC report data and the GRID model forecast data. The book-out transaction amounts, which have been deduced, have been shaded with a cross hatch. As can be seen from the table, if booked-outs transactions are excluded from both the GRID model NPC and Actual NPC, the use of the Commission approved methodology produces a level of sales that is consistent with the historical average, suggesting that the Commission approved method continues to be a viable way to forecast NPC.

Q. WHY THEN DOES TABLE 3-REB ON PAGE 8 OF THIS TESTIMONY SHOW SALES HIGHER THAN THE HISTORICAL AVERAGE AT CERTAIN MARKETS?

A. Market caps are only applied to the four markets identified in Table 3-REB. Markets such as Mid-C and Palo Verde do not have market caps applied. Even though there are no market caps applied to these markets, they tend to generate fewer sales in GRID than were made in the historical average period, thus offsetting the higher sales identified in Table 3-REB. Further, some markets result in a volume of sales less than the historical average and other markets result in a volume of sales more than the historical average, producing an offsetting effect.

It can be seen from the analysis in Table 3-REB, however, that GRID does produce more sales at COB than PacifiCorp was capable of making in the historical period. Given the economics of the COB market, the GRID model forecasts sales up to the market cap level in many hours of the year.

Similarly, GRID tended to produce higher sales at the Four Corners market than the historical average. The higher sales at Four Corners, however, can largely be explained by the loss of transmission to the Palo Verde market discussed above. Economic sales that were previously being made at Palo Verde must now be made at Four Corners.

Finally, the analysis shows that GRID consistently under-forecasts sales at Mead, even in the absence of Market Caps. The under-forecasting of sales at Mead is likely a byproduct of overly restrictive transmission limitations being applied to that market.

Q. IS THERE A WAY TO ADDRESS THE OVER FORECASTING OF SALES AT THE SPECIFIC MARKETS, SUCH AS COB AND FOUR CORNERS, IN TABLE 3-REB?

A. One alternative is to simply cap the overall modeled sales at the markets identified in Table 3-REB at a level that produces sales not exceeding the historical averages. That is, rather than using a market cap equal to the historical average, this approach sets the market cap through a few iterative GRID model runs so that the GRID model produces results that equal, but do not exceed, the historical average at any market or any time period. This can be accomplished through a simple approach that eliminates any controversy about whether the GRID model over or under forecasts sales relative to the historical levels for these markets. One problem with this approach is that it would not necessarily reflect the changes in PacifiCorp's portfolio that occurred within or subsequent to the historical period. It also does not address the under forecasting of sales at certain markets, such as Mona or Mead.

Q. HAVE YOU PREPARED SUCH AN ANALYSIS?

A. Yes. To perform the analysis, I performed three GRID runs. In the first run, I removed Market Caps altogether to evaluate the level of sales that would be generated in each market and each hour in the absence of Markets Caps. In the second run, I applied a cap to the sales generated in the first run at a level that would limit sales to no more than the historical average. Since this second run resulted in redispatch and modified sales levels at the different markets, I performed a third run where I reapplied the cap based on the output of the second run to address the redispatch resulting from the market caps applied in the second run. The monthly diurnal results of the analysis are detailed in Exhibit AWEC/201, summarized in Table 4-REB, below.

Table 4-REB
GRID Model Sales Variance from Historical Average

	AWEC Alternate			
	COB	4C	Mona	Mead
Jan	0%	0%	-25%	-24%
Feb	-0%	0%	-36%	-23%
Mar	-4%	-20%	-43%	-0%
Apr	-9%	-0%	-19%	-31%
May	0%	-0%	-64%	-71%
Jun	0%	0%	-0%	-46%
Jul	-0%	-0%	0%	-12%
Aug	2%	0%	1%	1%
Sep	-0%	-0%	0%	-11%
Oct	0%	-0%	-21%	-34%
Nov	0%	0%	-33%	-50%
Dec	-0%	-0%	-47%	-60%
Average	-1%	-2%	-24%	-30%

As can be seen, with the exception of a few megawatts of variance in August, this methodology produces sales up to, but never exceeding, the four-year historical average. The positives in August could have been eliminated with an additional iteration, although the effect would be negligible.

Q. WHAT IS THE IMPACT OF THIS ALTERNATIVE METHOD

A. Relative to PacifiCorp's Rebuttal filing, the impact of this alternative method is a $5,802,809 reduction to system NPC, with $1,510,044 of the reduction allocated to Oregon. In contrast, using the Commission approved method is a $26,538,162 reduction to system NPC, with $7,027,723 allocated to Oregon based on PacifiCorp's Rebuttal Filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I disagree that the "current methodology for forecasting sales activity is broken."[16] Such claims are based on a faulty analysis and incorrect understanding of the way that booked-out transactions impact Actual NPC. Accordingly, I continue to recommend that the currently approved market cap methodology be used to forecast net power costs. Maintaining the status quo is particularly important as Oregon transitions to the AURORA model for forecasting NPC.

Notwithstanding, if the Commission does decide to make any changes to the Market Cap methodology in this case, I recommend adopting the alternative methodology discussed above, where the Market Cap sales levels from the GRID model are set directly at, or below, the four-year average.

IV. BRIDGER COAL COMPANY MATERIALS AND SUPPLIES

Q. WHAT ANALYSIS DID YOU PERFORM WITH RESPECT TO BRIDGER COAL COMPANY MATERIALS AND SUPPLIES EXPENSES IN OPENING TESTIMONY?

A. In Confidential Exhibit AWEC/105, I performed an analysis evaluating the accuracy of PacifiCorp's forecast of materials and supplies expenses at Bridger Coal Company ("BCC"). The analysis reviews the BCC forecast prepared in the final TAM update filings in Docket Nos. UE 232 (2018 TAM), UE 339 (2019 TAM) and UE 356 (2020 TAM). The analysis showed that PacifiCorp's prior forecasts for materials and supplies expenses at BCC were grossly overstated in every year analyzed. In 2020, for example, the forecast was overstated by 32%. Accordingly, I recommended an adjustment based the historical variances.

[16] PAC/400, Staples/24:17-18.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp did not dispute that the BCC material and supplies expenses had been grossly overstated. PacifiCorp also acknowledged that it has historically overstated the cost per ton of coal from the BCC. Notwithstanding, PacifiCorp accuses me of "cherry-picking."[17/] PacifiCorp also has concerns with my calculations, including the use of a single royalty rate and the inclusion of reclamation volumes in my adjustment calculation.

Q. WAS YOUR ANALYSIS "CHERRY PICKING"?

A. As a threshold matter, it is unclear to me what meaning PacifiCorp intended by using the term "cherry-picking" when referring to my testimony. PacifiCorp seems to be objecting to the idea that an adjustment to a single cost item should be allowed. If that were the case, however, then no party could ever propose an adjustment to the utility's rates. Indeed, PacifiCorp's proposal to change the market caps method is just as much "cherry-picking" as my adjustment to BCC materials and supplies. The development of an accurate power cost forecast demands that each element of that forecast be independently predicted with as much precision as possible.

Q. DID YOU IGNORE RELEVANT EVIDENCE THAT CONTRADICTS YOUR PROPOSAL?

A. No. To the extent that PacifiCorp is arguing that I ignored offsetting factors, I also disagree with that characterization. PacifiCorp acknowledges it has materially overstated its budget for BCC in past proceedings. PacifiCorp acknowledges that "During 2018 through 2020, Jim Bridger plant coal received costs from BCC expressed on a cost per one million British thermal units (MMBtu) basis are [redacted] less than rates estimated in the referenced TAM filings."[18/] In conducting my review, I also noted this large discrepancy between the forecast costs

[17/] PAC/400, Staples/94:8-9.
[18/] PAC/600, Ralston/31:20-32:1 (internal citations omitted).

included in the TAM and the actual costs at BCC. I also noticed that some costs were higher and others cost were lower on a year-to-year basis and did not ignore those cost items when performing my analysis.

Q. WHY DID YOU FOCUS ON MATERIALS AND SUPPLIES EXPENSE?

A. While some costs were overstated and others understanded, consistent across all years was the fact that the materials and supplies expense budget was grossly higher than the amount that was actually incurred. While PacifiCorp is correct that there were many factors leading it to budget significantly more than it actually spent at BCC, I attributed the materials and supplies expense to be the primary driver of PacifiCorp' budget variance. Further, materials and supplies expenses are controllable costs. Therefore, there is no viable reason for a budget of these types of costs to be misstated by the magnitude identified in my Opening Testimony. It is important to point out that PacifiCorp did not attempt to explain why its materials and supplies expenses were so misstated relative to its forecast.

Q. DO YOU CONTINUE TO RECOMMEND AN ADJUSTMENT ASSOCIATED WITH BCC'S POOR BUDGETING PRACTICES?

A. Yes. I continue to recommend adjusting BCC's budgeted materials and supplies expense to reflect historical budget variances. In my updated adjustment detailed in Confidential Exhibit AWEC/203, I have accepted PacifiCorp's recommendation to adjust the royalties calculation to account for the slightly lower underground royalty rate on coal delivered from the underground mine, although the effects of this were negligible.

I also adjusted the calculation to reflect the fact that I had applied the per-ton amount to PacifiCorp's share of the coal volumes delivered to BCC, and then reapplied a second adjustment to reduce the volume for PacifiCorp's share again. This correction results in a larger adjustment value.

Finally, I did not make any adjustment to account for increased reclamation activities in 2018 through 2020. Reducing the expenses incurred in those years for reclamation activities would result in an increase to the budget variances, which I found to be unnecessary when performing the adjustment.

Q. WHAT IS THE IMPACT OF YOUR UPDATED RECOMMENDATION?

A. The updated recommendation in Confidential Exhibit AWEC/203 produces a $4,632,013 reduction to PacifiCorp allocated coal costs. On an Oregon-allocated basis, this adjustment amounts to a $1,175,112 reduction to NPC.

Alternatively, if the Commission agrees with the Company that my recommendation is too narrowly focused, I recommend that the Commission simply apply the overall BCC forecast error of [redacted] to coal from BCC in the test period. This alternative recommendation produces a $10,079,517 reduction to PacifiCorp allocated coal costs on a system basis, and a $2,557,109 reduction to NPC on an Oregon-allocated basis.

V. OTHER REVENUES

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO OTHER REVENUES?

A. I recommended including an Other Revenues forecast in TAM revenues, consistent with past TAM filings. Second, I recommended that Fly Ash Sales also be considered in the Other Revenues calculation.

Q. HOW DID PACIFICORP RESPOND?

A. Prior to Opening Testimony, AWEC requested copies of a contract with Seattle City Light ("SCL") for a portion of the output from the Stateline wind project. PacifiCorp, however, withheld the contract. AWEC also requested PacifiCorp perform an update to other revenues. PacifiCorp, however, refused to perform the analysis. Nevertheless, in its Reply Testimony, PacifiCorp stated that the Stateline contract has been terminated and that it should have reflected this in its Opening Testimony.[19/] This change increased Oregon-allocated NPC by $2,986,282.[20/]

Q. WHAT DO YOU RECOMMEND REGARDING THE STATELINE CONTRACT?

A. Since PacifiCorp did not include expiration of the Stateline contract in its initial application and was not forthcoming in providing that information in discovery prior to Opening Testimony, it would be reasonable for the Commission to exclude the costs associated with the expiration of the SCL Stateline contract from NPC in this proceeding. My recommendation, however, includes the costs associated with the expiration in the Other Revenue adjustment, despite these discovery shortcomings. My hope is that PacifiCorp will be more forthcoming on issues such as this in future proceedings.

Q. DO YOU CONTINUE TO RECOMMEND INCLUDING FLY-ASH SALES IN THE FORECAST OF OTHER REVENUES?

A. Yes. Fly ash sales are directly tied to the production at PacifiCorp's coal plants. Accordingly, I recommend that they also be considered in the Other Revenue forecast. From the revenue included in PacifiCorp's recent FERC Form 1, it appears the demand and prices for fly ash have increased since base rates were set in Docket No. UE 374. In the first quarter of 2021, for example, PacifiCorp made fly ash sales of $3,445,036, or $13,780,144 on an annualized basis. This amount is significantly higher than the $4,256,000 included in base rates in Docket No. UE 374. AWEC's recommendation is to use fly ash sales from the prior calendar year in the

[19/] PAC/400, Staples/93:4-5
[20/] Id. at 93:8-9.

TAM forecast. In this filing, AWEC is only proposing to include $6,504,276 in fly ash revenues based on the sales made in 2020. The higher sales recognized in 2021, however, will roll into the forecast in the 2023 TAM filing, if AWEC's recommendation is adopted.

Q. DO YOU AGREE WITH PACIFICORP THAT INCLUSION OF FLY ASH REVENUES IN THE TAM SHOULD BE MADE IN A GENERAL RATE CASE?

A. No. As PacifiCorp notes, the Commission has already included a provision for other revenues in the TAM, including items that are directly related to net power costs. Fly ash is a direct byproduct of burning coal and therefore directly related to fuel costs at coal fired power plants. The cost of coal is a net power cost. Therefore, fly ash is directly related to net power costs.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The effect of this recommendations is a $929,973 reduction to Oregon-allocated TAM revenues.

VI. CONSUMER OPT-OUT CHARGE

Q. WHAT ISSUE DID CALPINE IDENTIFY WITH RESPECT TO THE CONSUMER OPT-OUT CHARGE?

A. The Consumer Opt-Out Charge is a component of the costs a long-term direct access customer must pay to depart PacifiCorp's system. In addition to the Opt-Out Charge, long-term direct access customers must also pay a transition adjustment. The two charges function in tandem. In basic terms, the Opt-Out Charge is meant to recover stranded capital costs, whereas the transition adjustment charge is meant to recover stranded energy costs. The transition adjustment is calculated over the initial five-year period and the Opt-Out Charge is calculated from years six through 10, though it is recovered in the initial five-year period.

In this Docket, Calpine witness Higgins identified that PacifiCorp has imposed an artificial constraint when calculating the Opt-Out Charge, restricting the charge from being a negative value. Calpine recommends that the Opt-Out Charge be calculated as it was intended, including the possibility of negative values.

Q. HOW DID PACIFICORP RESPOND TO CALPINE'S RECOMMENDATION?

A. PacifiCorp opposes allowing the Consumer Opt-Out Charge to go negative. PacifiCorp claims that a negative opt-out charge will result in cost-shifting to other customers; however, the utility offers no evidence to support this claim.[21/]

Q. WHAT DOES IT MEAN THAT THE OPT-OUT CHARGE IS NEGATIVE?

A. The Opt-Out Charge represents the stranded capital costs associated with a departing customer. Accordingly, a negative Opt-Out Charge means that there are capital cost *benefits* associated with a customer permanently opting out of cost-of-service rates. That is, PacifiCorp avoids acquiring new resources, the cost of which exceed the embedded cost of resources that are stranded as a result of a customer departing, meaning that cost-of-service customers pay lower rates if a customer transitions to direct access. Given the pending closure of several major power plants, a negative opt-out charge is not a surprising result.

Q. DOES A NEGATIVE OPT-OUT CHARGE MEAN THAT PACIFICORP MUST PAY CUSTOMERS TO LEAVE?

A. No. A negative opt-out charge only means that there is a capital cost benefit associated with departing customers. A departing customer is still required to pay the stranded energy costs through the transition adjustment when departing. In this case, the negative opt-out charges are still much less than the transition adjustment, meaning customers must still pay a significant charge to depart PacifiCorp's system.

[21/] PAC/900, Meredith/4:14-5:20.

Q. IS A NEGATIVE OPT-OUT CHARGE CONSISTENT WITH THE COMMISSION'S DIRECT ACCESS RULES?

A. Yes. In fact, the possibility of a negative opt-out charge appears to be required by these rules, which state that "each Oregon retail electricity consumer of an electric company *will receive a transition credit* or pay a transition charge equal to 100 percent of the net value of the Oregon share of all economic utility investments and all uneconomic utility investments of the electric company …."[22/]

Q. ARE THERE INSTANCES WHERE CUSTOMERS HAVE BEEN PAID TO DEPART A UTILITY'S SYSTEM?

A. Yes. As shown in Exhibit AWEC/205, in 2008 Portland General Electric had a transition adjustment credit, and thus, paid customers to depart cost of service rates.

Q. SHOULD THE COMMISSION DEFER THE QUESTION OF WHETHER THE CONSUMER OPT-OUT CHARGE SHOULD BE ALLOWED TO GO NEGATIVE TO DOCKET NO. UM 2024, ITS DIRECT ACCESS INVESTIGATION?

A. No. Unlike the issues in Docket No. UM 2024, the question of whether the Consumer Opt-Out Charge should be negative is not a policy issue, it is simply a matter of applying the math and the Commission's rules to a PacifiCorp-specific charge that has existed since 2015. Certainly the question of whether the Consumer Opt-Out Charge should exist at all is one squarely within the scope of Docket No. UM 2024, but until that docket is resolved, the Consumer Opt-Out Charge is a component of the construct that exists today, and it should be implemented in a fair and consistent manner.

Q. WHAT DO YOU RECOMMEND?

A. I join Calpine in recommending the Commission reject PacifiCorp's proposal to modify the Consumer Opt-Out charge by restricting negative values.

[22/] OAR 860-038-0160(1) (emphasis added).

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2022 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/201

AWEC ALTERNATE ANALYSIS

(REDACTED VERSION)

Exhibit AWEC/201 contains Protected Information Subject to the General Protective Order in this proceeding and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2022 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/202

COMPARISON OF GRID MODEL SALES TO HISTORICAL ACTUAL SALES, INCLUDING DETAIL OF BOOKED-OUT TRANSACTIONS

Historical Market Cap Analysis

	Actaual NPC Sales Adj. For Book-Outs					Average	PacifiCorp Proposed Mkt Caps			Commission Approved Mkt Caps		
	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2016-2020	GRID	Δ to Avg.	%	GRID	Δ to Avg.	%
MWh Excl. Bookouts	6,018,797	6,651,663	7,765,501	4,947,298	4,885,911	6,053,834	4,612,503	(1,441,331)	-24%	5,700,017	(353,818)	-6%
Bookout MWh*	6,130,887	6,967,136	8,968,222	8,044,824	4,947,283	7,011,670	2,920,048	(4,091,622)	-58%	3,238,049	(3,773,621)	-54%
MWh Incl. Bookouts	12,149,684	13,618,799	16,733,723	12,992,122	9,833,194	13,065,505	7,532,551	(5,532,954)	-42%	8,938,066	(4,127,439)	-32%
Rev $ Excl. Bookouts	148,084,741	189,651,228	224,869,978	168,712,218	173,806,881	181,025,009	194,549,233	13,524,224	7%	248,354,153	67,329,144	37%
Bookout Rev. $*	141,563,258	176,562,582	239,685,688	215,933,990	135,193,456	181,787,795	120,035,515	(61,752,280)	-34%	132,558,404	(49,229,390)	-27%
Rev. $ Incl. Bookouts	289,647,999	366,213,810	464,555,666	384,646,208	309,000,337	362,812,804	314,584,748	(48,228,056)	-13%	380,912,558	18,099,754	5%

	Avg. Mkt Caps	Max Avg. Mkt Caps
GRID MWH	4,612,503	5,700,017
DART MWH	1,825,648	2,143,649
PSCo Exchange MWh	1,094,400	1,094,400
Total MWH	7,532,551	8,938,066
GRID $	194,549,233	248,354,153
DART$	61,986,990	74,509,880
PSCO Exchange	58,048,525	58,048,525
Total $	314,584,748	380,912,558

* From FERC Form 1

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2022 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/203

REVISED BCC MATERIALS AND SUPPLIES EXPENSE ANALYSIS

(REDACTED VERSION)

Exhibit AWEC/203 contains Protected Information Subject to the General Protective Order in this proceeding and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2022 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/204

REVISED OTHER REVENUE ADJUSTMENT, INCLUDING COAL ASH SALES

Other Revenues - Stand Alone TAM Adjustment

Line no		Total Company UE-374 Final	Total Company CY 2022 Initial	Factor	Factors UE-374	Factors CY 2022	Oregon Allocated UE-307 Final	Oregon Allocated CY 2022 Initial
1	OTHER REVENUES	(10,024,343)	-	SG	26.023%	26.482%	(2,608,598)	-
2	FLY ASH SALES	(4,256,000)	(6,504,276)	SG	26.023%	26.482%	(1,127,056)	(1,722,435)
3							-	
4	Total Other Revenue	(14,280,343)	(6,504,276)				(3,735,654)	(1,722,435)
5								
6				Decrease (Increase) in Other Revenues Absent Load Change				2,013,219
7								
8				Baseline Other Revenues in Rates			(3,735,654)	
9				$ Change due to load variance from UE 374 forecast			(43,090)	
10				Other Revenues in Rates using updated load forecast			(3,778,744)	
11								
12				**Decrease (Increase) in Other Revenues Including Load Change**				**2,056,309**
				Pac Proposed				2,986,282
				Adjustment				(929,973)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2022 Transition Adjustment Mechanism	)
	)

EXHIBIT AWEC/205

PORTLAND GENERAL ELECTRIC COMPANY NEGATIVE OPT-OUT CHARGES FROM 2008

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

This option was not available during Enrollment Periods A and B.

For Enrollment Period C (2004): No longer applicable

For Enrollment Period D (2005), No Longer Applicable **(C)**
(D)

For Enrollment Period E (2006); No Longer Applicable **(C)**

For Enrollment Period F (2007); No Longer Applicable **(C)**

For Enrollment Period G (2008), the Transition Cost Adjustment will be:

(1.043) ¢ per kWh	January 1, 2009 through December 31, 2009
(0.994) ¢ per kWh	January 1, 2010 through December 31, 2010
(0.720) ¢ per kWh	January 1, 2011 through December 31, 2011

For Enrollment Period H (2009), the Transition Cost Adjustment will be:

0.673 ¢ per kWh	January 1, 2010 through December 31, 2010
0.415 ¢ per kWh	January 1, 2011 through December 31, 2011
0.473 ¢ per kWh	January 1, 2012 through December 31, 2012

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1303

Docket No. UE 400 AWEC/100
Opening Testimony of Bradley G. Mullins

September 1, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PACIFICORP,	)
	)
2023 Transition Adjustment Mechanism.	)
	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

MAY 25, 2022

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a Consultant for MW Analytics, an independent consulting firm representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found in Exhibit AWEC/101.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's proposed $69,973,978 increase to Oregon revenues, including its forecast of 2023 Net Power Costs ("NPC") of $1,683,929,924 using the AURORA electric modeling software.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed PacifiCorp's filed testimony, workpapers and NPC models. I submitted multiple rounds of data requests and reviewed PacifiCorp's responses to those requests. Responses to select data requests are attached as Exhibit AWEC/102.

Q. PLEASE SUMMARIZE YOUR INITIAL RECOMMENDATIONS.

A. My initial recommendations are summarized in Table 1, below.

Table 1
AWEC Initial TAM Revenue Adjustment Estimates
Whole Dollars

Initial Filing	**69,973,978**
PTC Rate	(2,599,610)
Utah Schedule 34 Load	(5,091,533)
Utah DSM	(1,598,392)
Non-Firm Wheeling Error	(2,262,447)
Market Caps	(18,957,581)
PSCo Sale	(3,610,891)
Emergency Purchases	(2,388,803)
Total Initial Adjustments	(36,509,257)
Adjusted NPC	**33,464,720**

It should be noted that, while PacifiCorp's power cost update in this case would result in a 7.7% rate increase for industrial customers,[1] when combined with PacifiCorp's concurrent general rate case and its recent Power Cost Adjustment Mechanism filing, industrial customers are potentially looking at an overall rate increase of 19.2% on or about January 1, 2023.[2]

II. INITIAL ADJUSTMENTS

a. Production Tax Credit Rate

Q. WHAT PTC RATE DID PACIFICORP INCLUDE IN ITS FILING?

A. In its initial filing in this proceeding, PacifiCorp forecast a PTC rate of 2.7 cents per kWh. That value represents an increase from the 2.6 cents per kWh value that PacifiCorp agreed to include based on my Opening Testimony in Docket No. UE 390 (the "2022 TAM").[3]

1 Exh. PAC/403, Ridenour/1.
2 Docket UE 399, Exh. PAC/1110, Meredith/1; Docket UE 404, Exh. PAC/203, Meredith/1.
3 See UE 390, PAC/400, Staples/5:14-17.

Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?

A. The detailed mechanics of the PTC rate were discussed in my Opening Testimony in UE 390. As noted in my prior testimony, the IRS adjusts the PTC rate each year by applying an *inflation adjustment factor*.[4] The inflation adjustment factor is an indexed value that the IRS calculates based on the *GDP implicit price deflator*, which itself is an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. The Bureau of Economic Analysis publishes the GDP implicit price deflator each quarter, and from that information, the expected GDP implicit price deflator value for calendar year 2023 can be assessed.

Q. WHAT WILL THE PTC RATE BE IN 2023?

A. In Exhibit AWEC/103, I perform a forecast of the PTC rate for 2023 using the same analysis I presented in the 2022 TAM, where PacifiCorp accepted my recommendation. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for first quarter of 2022.[5] Based on that publication, it can be determined that the PTC rate will increase to 2.8 cents 2023 even if one assumes zero inflation for the remainder of 2022. Since inflation is expected to be positive in 2022, I recommend that a 2.8 cents per kWh rate be used in the 2023 TAM.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH THE FORECAST OF PORTLAND GENERAL ELECTRIC COMPANY?

A. Yes. In Exhibit AWEC/104, I have attached a non-confidential workpaper from Docket No. UE 402 where PGE forecast a 2.8 cent per kWh PTC rate for 2023.

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4 26 U.S.C. § 45(b)(2) (2022).

5 The published data is provided at https://apps.bea.gov/histdata/histChildLevels.cfm?HMI=7 (accessed May 23, 2022)

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. I estimate the impact of this recommendation as a reduction of $2,599,610 to Oregon-allocated TAM revenues.

b. <u>Utah Schedule 34</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO UTAH SCHEDULE 34.

A. PacifiCorp has a green tariff program in Utah under Utah Rate Schedule 34. Only one customer is participating in the program. In calculating Oregon's allocation factors, PacifiCorp has removed the Utah Schedule 34 Customer from Utah's dynamic allocation factors, which results in an increased amount of costs being allocated to Oregon customers. This treatment, however, is not consistent with the 2020 Protocol, which requires all loads PacifiCorp serves to be included in the load based dynamic allocation factors. Accordingly, I recommend that the jurisdictional allocation factors used in this proceeding be recalculated with the Utah Schedule 34 Customer's entire load included in the Load-Based Dynamic Allocation Factors.

Q. WHAT IS UTAH SCHEDULE 34?

A. Utah Schedule 34, attached as Exhibit AWEC/105, is a green tariff program available to large customers in Utah with loads exceeding 5,000 KW. Under the Utah Schedule 34 tariff, the terms and conditions of service are established in a "Renewable Energy Service Contract."

Q. HOW MANY CUSTOMERS ARE BEING SERVED ON UTAH SCHEDULE 34?

A. In response to AWEC Data Request 36, PacifiCorp stated that "[a]t this time, there is only one customer on Utah Schedule 34 during the test period." The Utah Public Service Commission ("UT PSC") approved this Utah Schedule 34 Customer's contract in Docket 16-035-27.[6]

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6 See https://psc.utah.gov/2016/06/23/docket-no-16-035-27/

Q. WHAT ARE THE PRICE TERMS AND CONDITIONS OF THE UTAH SCHEDULE 34 CUSTOMER'S RENEWABLE ENERGY SERVICE CONTRACT?

A. The terms and conditions of the contract were redacted in UT PSC Docket 16-035-27, and therefore, are unknown. Based on PacifiCorp's responses to discovery, such as its responses to AWEC Data Request 22 and AWEC Data Request 34, it appears that the Utah Schedule 34 Customer contract is structured like a green tariff program. The Utah Schedule 34 Customer has the ability to take services from at least eight different dedicated solar facilities with the ability to offset its tariff rates based on the cost of those resources.

Q. HOW IS SUCH A CONTRACT HANDLED UNDER THE 2020 PROTOCOL?

A. Section 3.1.6 of the 2020 Protocol states that "loads of Special Contract customers [are] included in Load-Based Dynamic Allocation Factors." While the Utah Schedule 34 contract is described as "Renewable Energy Service Contract," the 2020 Protocol defines it as a Special Contract, "a contract entered into between PacifiCorp and one of its retail customers with prices, terms, and conditions different from otherwise-applicable tariff rates."[7] Since the Utah Schedule 34 Customers would otherwise receive services based on the prices, terms and conditions of Utah Schedule 8 or Schedule 9, a Renewable Energy Service Contract approved under Utah Schedule 34, which provides for different prices, terms and conditions than the otherwise applicable rates, meets the definition of a Special Contract under the 2020 Protocol.

[7] 2020 Protocol, Appendix A at 7-8.

Q. DOES THE FACT THAT PACIFICORP'S GREEN TARIFF PROGRAM IN UTAH IS DEFINED IN A TARIFF IMPACT THE CONCLUSION THAT CONTRACTS ENTERED INTO UNDER SCHEDULE 34 ARE "SPECIAL CONTRACT" UNDER THE 2020 PROTOCOL?

A. No. The 2020 Protocol defines a special contract as one that includes prices that are "different from otherwise applicable tariff rates." Other than an administrative charge, Schedule 34 has no stated rates, and specifies that rates will be identified in each contract with a participating customer.[8] Therefore, Schedule 34 does not provide applicable tariff rates.

Q. HOW HAS PACIFICORP HANDLED THE UTAH SCHEDULE 34 CUSTOMER LOAD IN THIS FILING?

A. While the treatment was not described in testimony, it appears that the Utah Schedule 34 Customer loads are being excluded from the Load-Based Dynamic Allocation Factors, treatment which is inconsistent with the allocation of Special Contracts in the 2020 Protocol. There appears to have been substantial testimony discussing the interjurisdictional allocation of the Utah Schedule 34 Customer load in UT PSC Docket 16-035-27, although the testimony was redacted, and the Commission does not have the benefit of that discussion. Notwithstanding, in response to AWEC Data Request 35, PacifiCorp identified the following language in the Utah Schedule 34 Customer's contract:

> Energy: energy supplied by the renewable resources is excluded from jurisdictional allocation factors. Any energy supplied by PacifiCorp is included in the jurisdictional allocation factors.

> Capacity (coincident peak (CP)): capacity served by the renewable resource is excluded for the monthly renewable generation, not to exceed the customer's demand. Any capacity supplied by PacifiCorp is included in the monthly CP.

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[8] Exh. AWEC/105.

Thus, in the calculation of the Load-Based Dynamic Allocation Factors, the load of the Utah Schedule 34 Customer is being offset by the generation supplied by the dedicated green tariff resources PacifiCorp is purchasing for the customer.

Q. DOES THE UTAH SCHEDULE 34 CUSTOMER'S CONTRACT HAVE ANY BEARING ON THE ALLOCATION OF COSTS UNDER THE 2020 PROTOCOL?

A. No. The 2020 Protocol generally does not allow customers or states to avoid their share of fixed system costs through the Load-Based Dynamic Allocation Factors by entering into an agreement with special terms regarding interjurisdictional allocation. Indeed, Appendix G of the 2020 Protocol establishes that, for Special Contracts both with and without Ancillary Service Contract Attributes, "Loads of Special Contract customers **will be included** in all Load-Based Dynamic Allocation Factors."[9]

Furthermore, PacifiCorp's Oregon customers have long been prohibited from such treatment with respect to Direct Access and the New Load Direct Access Program. Those programs require customers to pay transition adjustment charges for a period of 10-years to opt-out of cost-of-service rates, a requirement of Section 3.1.8 of the 2020 Protocol. Thus, the treatment in Utah Schedule 34 Customers is inequitable because Utah avoided an allocation of any generation or transmission costs, other than the dedicated resources, used to serve the Utah Schedule 34 Customer's load. Oregon Direct Access customers pay for their own transmission and supply their own energy for their full requirements yet are not afforded this same treatment. The Utah Schedule 34 Customer supplies only partial requirements from the green tariff resources, which rely heavily on PacifiCorp's generation fleet for integration and shaping services. The Utah Schedule 34 Customer also does not pay for the cost of OATT transmission

[9] 2020 Protocol, Appendix G, p. 1 (emphasis added).

to deliver its dedicated resources to its load. Thus, the Utah Schedule 34 Customer imposes more costs on PacifiCorp's system, while being provided more favorable treatment than Oregon Direct Access customers.

Q. HOW HAS PACIFICORP HANDLED THE DEDICATED SOLAR RESOURCES IN ESTIMATING NPC?

A. It is not clear. In Opening Testimony, PacifiCorp did not describe or mention these facilities, let alone its unique treatment of the resources in the calculation of NPC. In its workpaper "ORTAM23 NPC CONF," Tab "UT Solar Adjustment," it appears that PacifiCorp made an adjustment where it repriced a portion of the facilities' energy based on Utah Schedule 37 rates effective in 2018. Notwithstanding, in response to AWEC Data Request 20, PacifiCorp identified a significant error associated with that workpaper. In its May 5, 2022 List of Corrections and Omissions, PacifiCorp noted that correcting this error will decrease total-company Net Power Costs by $11,400,000, although PacifiCorp did not provide the corrected workpapers.

Q. DID THE UTAH SCHEDULE 34 DEDICATED RESOURCES FOLLOW OREGON'S RESOURCES PROCUREMENT GUIDELINES?

A. No. A request for proposal meeting Oregon's procurement guidelines was not undertaken. In Data Request 22, AWEC requested the economic analyses supporting the Appaloosa I-A and Appaloosa I-B projects. PacifiCorp responded, for example, that no such economic analysis was undertaken because "100 percent of the costs associated with the PPAs are passed through to an individual customer under Utah Electric Service Schedule 34."

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Utah Customer load be considered consistent with the 2020 Protocol. Specifically, I recommend the entire amount of the Utah Customer load and demand be included in jurisdictional allocation factors, as required by the 2020 Protocol.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This recommendation will have impacts in both this proceeding and the ongoing general rate case in Docket No UE 399. PacifiCorp provided the calculation of System Energy ("SE") and System Generation ("SG") interjurisdictional allocation factors in response to AWEC Data Request 14. As can be seen from the attachment to that response, significant adjustments were made reducing Utah's allocation factors. In AWEC Data Request 36, PacifiCorp was requested to provide the loads of the Utah Schedule 34 Customer. PacifiCorp objected and did not provide the information. In response to AWEC Data Request 38, PacifiCorp described the specific adjustments that it made to the Utah allocation factors, including Demand Side Management, Special Contract Load Curtailment and the Utah Schedule 34 Customer. In the Confidential Attachment 2 of PacifiCorp's response to AWEC Data Request 39, PacifiCorp provided greater detail of the adjustments to Utah's allocation factors. From that response, it appears that PacifiCorp included the Utah Schedule 34 Customer Load in the Special Contract category, along with Special Contract load curtailments, although the precise load is unknown. Accordingly, in Table 2, below. I have approximated the impact of PacifiCorp's special treatment for the Utah Schedule 34 Customer on Oregon's allocation factors based on my understanding of the approximate volume of Special Contract load curtailments.

Table 2
Approximate Impact of Utah Schedule 34 Customer on Allocation Factors

	SE	SG
PacifiCorp Filed	25.07%	26.07%
With Utah Sch. 34 Load	25.17%	25.88%

Based on the above calculation, PacifiCorp's treatment of excluding the Utah Schedule 34 Customer load from Utah's allocation factors has resulted in an approximate $5,091,533 increase to the TAM revenue requirement in this proceeding Since the workpapers PacifiCorp provided contained an error, however, it is not possible to fully estimate the corresponding impact of this recommendation on the cost of the Utah Schedule 34 Customer's dedicated resources.

c. Utah Demand Side Management

Q. WHAT ADJUSTMENT DOES PACIFICORP MAKE TO THE LOAD BASED DYNAMIC ALLOCATION FACTORS FOR UTAH DEMAND SIDE MANAGEMENT?

A. In response to AWEC Data Request 37, Confidential Attachment 2, it can be noted that PacifiCorp made an adjustment to Utah's demand for a demand side management program.

Q. HOW IS DEMAND SIDE MANAGEMENT CONSIDERED IN THE 2020 PROTOCOL?

A. In Section 3.1.2.1 of the 2020 Protocol, "[b]enefits from [demand-side management] programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors."

Q. IS IT NECESSARY FOR PACIFICORP TO INCLUDE AN ADJUSTMENT FOR UTAH DEMAND-SIDE MANAGEMENT IN THE ALLOCATION FACTORS?

A. No. To the extent that the Coincident Peaks are being reduced by Utah's demand side management programs, those reductions would have otherwise already been considered in Utah's load forecast. Further, Oregon does not receive a similar reduction to its peak load requirements for its investment in energy efficiency through the Energy Trust of Oregon.

Q. WHAT DO YOU RECOMMEND?

A. I recommend removing the Utah demand-side management adjustment from the calculation of the Load-Based Dynamic Allocation Factors. This recommendation results in a $1,598,392 reduction to Oregon allocated NPC.

d. <u>Oregon Situs Assignment Calculations</u>

Q. PLEASE DESCRIBE THE ERROR PACIFICORP MADE IN ITS SITUS ASSIGNMENT CALCULATIONS.

A. In workpaper "TAM Allocation - CY 2023 - Initial Filing," Tab "Oregon Situs - 2023 Initial," PacifiCorp identified an Oregon situs adjustment reduction to NPC of $430,221. In AWEC Data Request 45, PacifiCorp was requested to provide workpapers supporting the hardcoded values that were used to calculate that adjustment. In its response, PacifiCorp omitted the workpapers supporting the reasonable energy price calculations for situs assigned qualifying facility resources. Accordingly, I have been unable to validate the Oregon situs assignment adjustment. I recommend PacifiCorp provide an explanation of how situs assigned qualifying facility resources are handled in its reply and provide workpapers supporting the situs assignment calculations.

e. Non-Firm Wheeling Error

Q. HAVE YOU IDENTIFIED ANY ERRORS IN PACIFICORP'S CALCULATION OF NON-FIRM WHEELING EXPENSE?

A. Yes. Oregon is the only state using 48-months of non-firm wheeling expense. Other states use 12 months of data, consistent with other wheeling expenses. Accordingly, when calculating wheeling expenses for Oregon in the workpaper "GNw_Wheeling CONF," PacifiCorp will normally deduct the non-firm wheeling expense calculated over 12 months and add back the non-firm wheeling expense calculated over 48 months. In this proceeding, however, PacifiCorp's wheeling workpaper contained an error. The workpaper added back the non-firm wheeling expense calculated over 48 months for just 6 months of the test period and failed to deduct the wheeling expenses calculated over 12 months. Correcting the workpaper reduces total-Company wheeling expense by $8,914,255, with $2,262,447 of the reduction allocated to Oregon.

f. Short-Term Transmission

Q. HOW IS SHORT-TERM FIRM TRANSMISSION INCLUDED IN AURORA?

A. In addition to long-term transmission, PacifiCorp models short-term transmission, including short-term firm and non-firm transmission, as distinct links in AURORA. Since those transactions often occur in day ahead and real-time markets, PacifiCorp does not necessarily know how much short-term firm or non-firm transmission it will have available in the test period. Accordingly, in past proceedings PacifiCorp has modeled short-term firm transmission in GRID using 48 months of historical data.

In this proceeding, however, PacifiCorp's treatment of short-term transmission is not clear. The specific short-term link capacities included in AURORA may be found in the workpaper "Aurora GN Transmission Links CONF", tab "1 Transmission Links." In AWEC

Data Request 10, AWEC requested PacifiCorp provide the workpapers used to calculate the transmission capacity for these short-term firm transmission links. In response, PacifiCorp provided two files that contained actual short-term and non-firm transmission in calendar year 2021. The specific link capacity values input into AURORA, however, were not contained in the files PacifiCorp provided. Accordingly, I was unable to verify how PacifiCorp modeled short-term transmission in this proceeding.

Q. IS PACIFICORP'S APPROACH CONSISTENT WITH ITS PAST PRACTICE?

A. Based on its response to AWEC Data Request 10, it is possible that PacifiCorp has modeled short-term transmission transactions using data from calendar 2021, which would represent a modeling change from past proceedings, which have used 48 months of data. This was not listed as a modeling change or discussed in testimony.

Q. DID YOU INDEFINITY ANY ERRORS IN THE FILE PACIFICORP PROVIDED?

A. Yes. There were many short-term transmission purchases in the data that PacifiCorp provided which were marked as excluded. These link capacities were allegedly "intra-bubble" transactions occurring within the same transmission area, and thus, not requiring separate transmission capacity in AURORA. Upon review, however, many of these links are not appropriately excluded because they in fact occur between two separate transmission areas in PacifiCorp's new transmission topology. These included transmission between the Red Butte substation and the Mead Market and transmission from Avista's system to the Mid-C market. The Red Butte substation is in Southern Utah and Mead is a market hub in Northern Nevada. Accordingly, it would have been more appropriate to model transmission between these two points as a link between Utah South and the Mead Market. PacifiCorp uses wheeling on Avista's system to facilitate transfers from Western Idaho. Accordingly, transactions from

Avista's system to the Mid-C market, which were also excluded, are appropriately modeled as a link between Idaho West and the Mid-C Market.

Further, in the data PacifiCorp provided, PacifiCorp did not detail short-term transmission that it has acquired on PacifiCorp Transmission's system. In addition to the long-term link capacities on PacifiCorp Transmission's system, PacifiCorp also can procure short-term firm and non-firm transmission on PacifiCorp Transmission's system to serve its load requirements. This capability was not considered in the long-term link capacities, or the data provided in response to AWEC Data Request 10.

Q. WHAT DO YOU RECOMMEND?

A. Given the capability of AURORA, which provides more flexibility in modeling transmission, it may be possible to transition to a more streamlined approach to modeling short-term transmission. I recommend PacifiCorp respond to the issues above in Reply Testimony and explain how it has modeled short-term transmission in AURORA. I may propose an adjustment depending on the information PacifiCorp provides on this topic.

g. <u>GRID Market Caps</u>

Q. WHAT DOES PACIFICORP PROPOSE RELATED TO MARKET CAPS?

A. Market Caps were a specific modeling input in the GRID model used to address what PacifiCorp saw as a shortcoming in the way the GRID model overoptimized forecast sales transactions. In this proceeding, PacifiCorp states that AURORA "does not consider load requirements, transmission constraints, market illiquidity, or static assumptions about market prices that prevent the Company from making sales or purchases at the forecast price,"[10] and

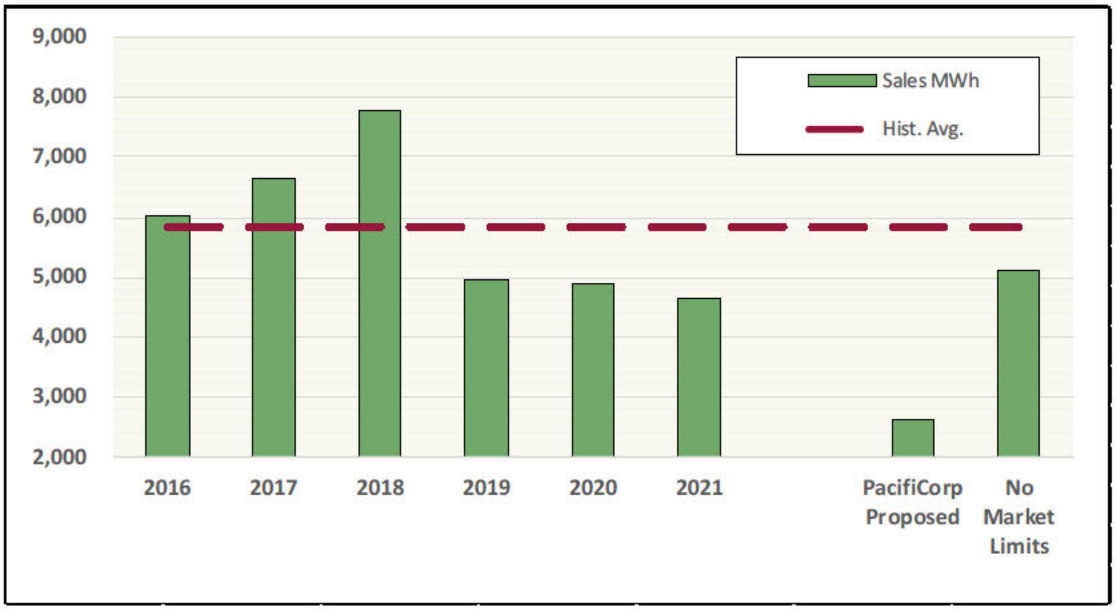
[10] PAC/100, Wilding/28 at 3-5.

proposes new modeling to duplicate Market Caps in the AURORA model. Since the AURORA model does not contain an input for Market Caps, PacifiCorp used a work-around to duplicate GRID Market Caps in AURORA. Specifically, PacifiCorp has attempted to duplicate Market Caps in AURORA by modeling sales transactions in a separate transmission area with a fictitious transmission link between the market hub and with the link capability corresponding to the Market Cap limits. In addition, PacifiCorp has proposed to calculate the limits using average data, even though the Commission has repeatedly rejected that approach.

Q. WHAT DO YOU RECOMMEND?

A. Given the move to AURORA, I recommend that Market Caps be eliminated. The AURORA model is already producing a level of sales that is significantly below the historical levels, so continuing to apply a limit on market sales is no longer necessary. In Exhibit AWEC/106, I perform an analysis comparing the sales forecast in AURORA to the historical level of sales. I detailed this analysis both including and excluding book-out transactions. The result of this analysis, excluding book-out transactions, can be seen in Figure 1, below.

Figure 1
Sales Volumes Excluding DA/RT and Book-Outs



To form an apples-to-apples comparison, it is necessary to either include or exclude book-out transactions in both the historical data and the forecast data. PacifiCorp's analysis in Direct Testimony is therefore not accurate because it ignores book-outs, leading to an "apples-to-oranges" comparison. In the above analysis, I excluded both book-outs and the DA/RT volumes from the calculation. As can be seen, when the Market Cap modeling is eliminated, the level of sales produced is still less than the historical average. It is also in line with the level of sales experienced since 2019, although higher than average sales volumes are expected given high market prices. Thus, with the move to AURORA, it is not necessary to duplicate the GRID Market Cap modeling assumption.

Q. ARE HIGHER SALES VOLUMES EXPECTED WITH HIGH MARKET PRICES?

A. Given high market prices, higher sales revenues and volumes would otherwise be expected in the test period.

Q. ARE SALES VOLUMES ALSO INFLUENCED BY THE DA/RT ADJUSTMENT?

A. Yes. If there is a concern with the volume of sales included in NPC, the Commission might be better served with adjusting the volumes produced in the DA/RT adjustment, than duplicating GRID Market Caps in AURORA. The volumes produced in the DA/RT adjustment contribute more volume to the sales forecast in this case than the AURORA model. These volumes, however, are a perfunctory feature of the DA/RT adjustment, and have zero impact on NPC. The DA/RT volumes are somewhat arbitrary because they assume that PacifiCorp balances 100% of its net sales and purchases with structured products, which does not necessarily correspond to its actual practice. Since these volumes don't impact NPC, the methodology used to derive them has not received attention in past proceedings.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing the duplicated GRID Market Cap modeling results in a $73,603,841 reduction to total-Company NPC, with approximately $18,957,581 of the reduction allocated to Oregon.

h. <u>Hayden</u>

Q. HAS PACIFICORP EXECUTED A NEW COAL SUPPLY AGREEMENT FOR THE HAYDEN PLANT?

A. Yes. This contract is described at PAC/200, Owens/22 at 16-18.

Q. DID PACIFICORP PERFORM AN ECONOMIC ANALYSIS TO EVALUATE THE CONTRACT?

A. No. In response to AWEC Data Requests 60 and 61, PacifiCorp states that it did not perform any economic analysis with respect to the new contract.

Q. IS THE AGREEMENT PRUDENT?

A. No. Hayden is scheduled to be depreciated and removed from rates in Oregon at the end of 2023. This was noted in response to AWEC Data Request 50. In section 4.1.5 of the 2020

Protocol, PacifiCorp was required to "make State-specific recommendations to Commissions for the treatment of Hayden Units 1 and 2." This was to occur on or before February 1, 2021. Based on PacifiCorp's response to AWEC Data Request 67, that recommendation never occurred. Entering into a long-term agreement immediately before a plant is expected to be retired from rates with no supporting economic analysis is not prudent.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission find the contract described at PAC/200, Owens/22 at 16-18 to be imprudent. I recommend that Oregon ratepayers not be subject to any liquidated damage costs in connection with removing Hayden 1 and 2 from Oregon rates in 2023, consistent with the 2020 Protocol.

i. <u>Craig</u>

Q. HOW DOES PACIFICORP CALCULATE COAL COSTS FOR THE CRAIG POWER PLANT?

A. Coal costs for Craig power plant are identified in the workpaper of witness Owens titled "CRAIG FLLT 2023 TAM DF Cycling." The costs of the Craig facility are based on the costs of the Trapper mine, of which PacifiCorp is a part owner.

Q. HOW DOES PACIFICORP DERIVE THE COST ESTIMATES FOR THE TRAPPER MINE?

A. The values appear to be driven by a budget from the mine itself. There are also adjustments that need to be made to remove profit interests and other items, although those details were not provided in the Owens workpaper.

Q. DID YOU REQUEST FURTHER INFORMATION REGARDING THE BUDGET PROVIDED BY THE TRAPPER MINE?

A. Yes. In AWEC Data Requests 62 through 66, I requested additional information regarding the budget for the Trapper mine. The budget itself was several years out of date, so I was concerned with its accuracy.

Q. WAS PACIFICORP ABLE TO PROVIDE ANY INFORMATION TO VALIDATE THE ACCURACY OF ITS BUDGET?

A. No. PacifiCorp repeatedly stated that "[t]his requested information is not available because Trapper mine does not provide PacifiCorp with that level of detail on plant additions." Notwithstanding, in response to AWEC Data Request 60, PacifiCorp claims it made an error by excluding certain detail from its calculation, detail which it alleged was not provided by the Trapper mine.

Q. WHAT DO YOU RECOMMEND?

A. Given that PacifiCorp has been unable to substantiate the costs from the Trapper Mine, I recommend PacifiCorp provide further information on the budget process and explain why the information is unavailable. I may recommend an adjustment after reviewing PacifiCorp's testimony on this issue.

j. <u>PSCo Contract</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE PSCO CONTRACT.

A. The Public Service Company of Colorado ("PSCo") contract is a new sales agreement replacing a legacy exchange agreement. In the Confidential Attachment to Data Response 24, PacifiCorp provided a memorandum that describes the confidential terms of the contract and describes PacifiCorp's decision to execute the new agreement, including the price and term of the contract.

Q. IS THE CONTRACT ECONOMIC?

A. No. Based on the time that it was issued, the contract price was below market by a large margin. In Exhibit AWEC/107, I provide an analysis comparing the new PSCo contract with the November 08, 2021, OFPC, which was the latest OFPC at the time the agreement was executed. The contract was less than 50% of the 2023 forward market at the time it was executed.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THIS CONTRACT?

A. Yes. Both Craig and Hayden are operating at very low capacity factors in the study period. In addition, AURORA is producing a large volume of trapped energy from the Colorado transmission area in the study period, indicating there is generation from Craig and Hayden that is unable to be transmitted to PacifiCorp's main system. PacifiCorp models the PSCo sale as a Demand Side Management resource, which appears to be producing unintended consequences on the Craig and Hayden facilities. My understanding was the contract was designed to avoid trapped energy from the Craig and Hayden facilities, but the opposite effect is being observed in the AURORA model.

Q. WHAT DO YOU RECOMMEND?

A. Based on the analysis in Exhibit AWEC/107, I recommend the Commission find that the PSCo contract was imprudent and recommend that the new PSCo contract be repriced based on the November 08, 2021 OFPC. The impact of this recommendation is a $14,020,653 reduction to total-Company NPC with $3,610,891 of the reduction allocated to Oregon.

k. <u>Emergency Purchases</u>

Q. WHAT ARE EMERGENCY PURCHASES?

A. Emergency purchases are a modeling convention that PacifiCorp applies in AURORA, which is designed to prevent the model from failing to find a dispatch solution in instances where generation is insufficient to serve the demand in a particular transmission area. Such a situation might occur when the model fails to find a dispatch solution that satisfies all constraints in the model. Emergency purchases are included as a resource in each transmission area and provided with an arbitrarily high dispatch bid-adder of $1000/MWh. Thus, the emergency purchase resource is designed to be a last resort resource in cases where the model is unable to find a satisfactory solution for a particular transmission area. If the model is developed properly, emergency purchases are expected to be minimal.

Q. HOW ARE THE COSTS OF EMERGENCY PURCHASES INCLUDED IN NPC?

A. When calculating NPC, PacifiCorp does not use the $1000/MWh dispatch price assumed in AURORA, but instead, assigns the emergency purchases a price corresponding to 150% of the nearest market price.

Q. WHAT VOLUME OF EMERGENCY PURCHASE IS INCLUDED IN PACIFICORP'S NPC STUDY?

A. Emergency purchase comprise approximately 8% of the total volume of purchase in the AURORA model. Thus, even though emergency purchases are designed as a stop gap measure to prevent the model from failing, they comprise a material portion of the purchases being made to serve loads.

Q. DO EMERGENCY PURCHASES REPRESENT AN ACTUAL COST TO PACIFICORP?

A. PacifiCorp excludes emergency purchases from the calculation of the DA/RT adjustment. If these high-cost purchases represent actual historical cost, they are appropriately considered when evaluating the average purchase price modeled in AURORA to the average DA/RT purchase price based on historical data. Stated differently, the DA/RT adjustment already considers the high cost of making emergency purchases when the system is constrained so it is unnecessary to add additional cost into NPC for the emergency purchases generated in AURORA.

Q. IS THE MODEL FUNCTIONING CORRECTLY IF IT IS PRODUCING SUCH A HIGH LEVEL OF EMERGENCY PURCHASES?

A. No. Such a high level of emergency purchases is an indication that there is a problem with the model. It is possible that the high volume of emergency purchases may be driven by faulty modeling assumptions, although I have been unable to identify the cause of the high level of emergency purchases.

Q. WHAT DO YOU RECOMMEND?

A. Given that the cost of emergency purchases made historically is already reflected in the DA/RT adjustment, I recommend that the 150% adder applied to emergency purchases be eliminated. The impact of this adjustment is a $9,274,658 reduction to total-company NPC, with approximately $2,388,803 allocated to Oregon.

l. <u>Northwest Pipeline Tax Reform Refund</u>

Q. PLEASE DESCRIBE THE REFUND AT ISSUE IN THE ONGOING NORTHWEST PIPELINE RATE CASE.

A. As a part of its prior rate case, FERC Docket No. RP17-346, the Northwest Pipeline agreed to defer the impacts of tax reform in a regulatory asset. Shippers are currently in the process of negotiating a prefiling settlement for Northwest Pipeline's upcoming rate case, which will be filed on June 1, 2022 if a settlement is not reached. In either case, approximately $130,000,000 of funds have accrued to the regulatory asset that will be returned to shippers, including PacifiCorp, starting January 1, 2023. I recommend the benefit of this refund—once it is determined, either through the filing of a settlement agreement or the filing of Northwest Pipeline's rate case—be included as a reduction to the TAM revenues in this proceeding.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1304

Docket No. UE 416 AWEC/100
Opening Net Variable Power Cost Testimony of Bradley G. Mullins
(redacted version)

September 1, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request For a General Rate Revision.	)
	)

OPENING NET VARIABLE POWER COST ("NVPC") TESTIMONY

OF

BRADLEY G. MULLINS

ON BEHALF OF

THE ALLIANCE OF WESTERN ENERGY CONSUMERS

Protected Information Subject to Modified General Protective Order
(REDACTED)

Highly Confidential Information Subject to Modified Protective Order No. 23-138
(REDACTED

May 24, 2023

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found in **Exhibit AWEC/101**.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Portland General Electric Company ("PGE" or "Company")).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PGE's proposed $867,132,398 Net Variable Power Costs ("NVPC") forecast for calendar year 2024,[1] including my review of the MONET modeling supporting the 18.7% or $136,894,052 increase to NVPC relative to the $730,238,346 NVPC forecast in PGE's final update in Docket UE 402 (the "2023 AUT") for calendar year 2023.[2]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The NVPC rate increase PGE is seeking in this proceeding is not justified. As I discuss below, the increase PGE proposes is being driven by several erroneous assumptions and inaccurate modeling approaches. I recommend the Commission adopt several adjustments to PGE's proposed NVPC that will result in a more accurate forecast of 2024 costs. My

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1 *See* Docket No. UE 416, PGE's March 31, 2023 MONET Update (March 31, 2023).
2 *See* Docket UE 402, PGE's November 15, 2022 MONET Update (Nov. 15, 2022).

recommendations are summarized in Confidential Table 1, below, followed by a brief description of each issue. offset

Confidential Table 1
AWEC Recommended AUT Adjustments
(Whole Dollars)

1	**PGE March 31, 2023 Update**	**$ 867,132,398**
2	**Adjustments:**	[redacted]
3	Flexibility Down Reserves	[redacted]
4	Washington CCA Allowances	[redacted]
5	Mid-C Specified, Zero Carbon Sales	[redacted]
6	Production Tax Credit Rate	[redacted]
7	Gas Option Placeholder	[redacted]
8	Reliability Contingency Event	[redacted]
9	Thermal Parameters	[redacted]
10	Beaver Cycling	[redacted]
11	Carty Outage Rate	[redacted]
12	2023 AUT - Trans. RDC	[redacted]
13	2023 AUT - BP-24 Wheeling Rates	[redacted]
14	2024 Wheeling Expenses	[redacted]
15	Biglow Capacity Factor	[redacted]
16	Balancing Impacts*	[redacted]
17	Total Adjustments	**(161,910,711)**
18	**Adjusted**	**$ 705,221,687**

*Counterbalancing impacts of all adjustments

Flexibility Down Reserves: I recommend flexibility down reserves be allocated to thermal resources prior to being allocated to hydro resources, which eliminates unnecessary hydro spill in MONET.

Washington Climate Commitment Act Allowances: I recommend that Mid-Columbia ("Mid-C") index prices be adjusted for the impact of the Washington Climate Commitment Act ("CCA") and that allowance costs be removed because they will be offset by increased revenue from selling Washington CCA Compliant power products.

Specified Source Non-Emitting Sales: I recommend modeling incremental revenues from the sale of non-emitting power from specified sources in the Mid-C bilateral market.

Production Tax Credit ("PTC") Rate: I recommend that the production tax credit rate increase to 30 cents per kWh, consistent with inflationary trends expected through the end of 2023.

Gas Option Placeholder: I recommend that the cost of a placeholder gas option be removed from NVPC on the basis that it is both imprudent and an extrinsic value, which based on Commission precedent is not includible in forecast NVPC.

Reliability Contingency Event: I recommend PGE's provisional costs for a reliability contingency event be removed from the NVPC forecast because the median conditions included in the forecast do not also consider beneficial operating events, such as low and negative prices during oversupply events.

Thermal Parameters: I recommend the thermal plant capacities be updated to be consistent with the thermal capacities PGE reports to the EIM in its master file submissions.

Beaver Cycling: I recommend Beaver cycling parameters be updated to be consistent with its actual historical cycling operations.

Carty Outage Rate: I recommend Carty's outage rate be adjusted to remove an imprudent outage from 2021, which non-Company parties identified in Joint Testimony in Docket No. UE 406.

2023 AUT Stipulation – Bonneville Power Administration ("BPA") 2023 Reserves Distribution Clause: I recommend that the 2023 BPA Reserves Distribution Clause ("RDC") benefits be returned to ratepayers in this docket consistent with the Stipulation in the 2023 AUT.

2023 AUT Stipulation – BP-24 Wheeling Rates: I recommend the difference between the actual BP-24 wheeling rates and the BP-24 wheeling rates assumed in the 2023 AUT be returned to ratepayers in this docket consistent with the Stipulation in the 2023 AUT.

BPA 2024 Wheeling Expense: I recommend an unsupported rate increase assumed for BPA wheeling rates in the fourth quarter of 2024 be removed from the NVPC forecast.

Biglow Capacity Factor: I recommend that the capacity factor for Biglow be calculated over the period 2019 through 2021, excluding the abnormal conditions in 2022 resulting from turbine failures.

II. FLEXIBILITY DOWN RESERVES

Q. WHAT IS YOUR RECOMMENDATION RELATED TO FLEXIBILITY DOWN RESERVES?

A. The reserves logic and Visual Basic models that PGE uses to forecast the cost of reserves in the MONET model are severely flawed. The reserves modeling that PGE uses is not optimized with system dispatch and results in sub-optimal, uneconomic hydro dispatch. The reserves logic not only results in dispatching hydro output in uneconomic hours, but includes an assumption that PGE will voluntarily spill, *i.e.*, diverting the water through the impoundment without running it through the generation turbines, a large volume of hydro energy. In fact, in PGE's modeling, this spill occurs in the majority of days in the study year, which is not consistent with how PGE operates its system, nor a prudent technique for holding reserves. The principal cause of this inefficient hydro dispatch is the treatment of downward flexibility reserves, which are being incorrectly allocated entirely to hydro resources without considering the downward flexibility reserves otherwise available at no cost from thermal resources. To correct this issue, I propose an adjustment that allocates downward flexibility reserves to thermal resources prior to being allocated to hydro resources. This change results in a more efficient hydro dispatch and a more accurate forecast of the cost of reserves to PGE. Adopting this change produces $[redacted] reduction to PGE's NVPC forecast.

Q. WHAT ARE RESERVES?

A. Reserves are dispatchable generation capacity that PGE must withhold, or have available, to be capable to respond to uncertainty associated with loads, generation and intermittent resources. The classic example of reserves are contingency reserves, in which a utility must have generation capacity available to respond within ten minutes in a contingency event, such as a forced outage. Thus, rather than selling the full output of a resource into the market, a resource that is holding reserves must be dispatched down in order to respond to such events, resulting in an opportunity cost to the utility. There are several different types of reserves, including both upward reserves and downward reserves. Upward reserves represent capacity that is available to be ramped up within a specified timeframe to accommodate things such as a generator tripping offline or an unexpected increase to load. Downward reserves, on the other hand, represent capacity that is available to be ramped down within a specified timeframe to accommodate things such as an unexpected increase in variable generation or unexpected reduction to load. As noted above, the issue I have identified specifically has to do with downward flexibility reserves.

Q. WHAT CATEGORIES OF RESERVES DOES PGE MODEL IN MONET?

A. PGE models reserves for an increasing number of different reserve categories. First, PGE calculates contingency reserves based on the NERC/WECC standard definitions of 1.5% of load and 1.5% of generation. Contingency reserves are an upward reserve requirement. Second, PGE calculates regulating reserves equal to 1.0% of load. Regulating reserves are modeled as an upward reserve requirement. Third, PGE calculates day-ahead flexibility reserves based on an analysis of historical wind variances between the day-ahead and hour-ahead. Day-ahead flexibility reserves are modeled both as an upward reserve requirement and a downward reserve requirement. Fourth, PGE calculates hour-ahead flexibility reserves based upon historical wind, solar and load variances between the hour-ahead and actual dispatch. Similar to day-ahead flexibility reserves, hour-ahead flexibility reserve requirements are also modeled both as an upward reserve requirement and a downward reserve requirement. Fifth, PGE calculates frequency reserves based on a heuristic analysis. Frequency reserves are modeled as an upward reserve requirement.

Q. DO YOU AGREE WITH ALL OF THESE RESERVE CATEGORIES?

A. No. Many of these reserve requirements are overlapping and not additive. Further, some of the reserve requirements do not actually impact hourly system dispatch, such as day-ahead reserves. For purposes of this testimony, I have not addressed all these issues. Given the relative materiality, this testimony instead focuses on the MONET model logic flaw surrounding downward flexibility reserves that is leading to inaccurate system dispatch.

Q. DO UPWARD RESERVES AND DOWNWARD RESERVES IMPOSE THE SAME COSTS ON A UTILITY'S RESOURCE PORTFOLIO?

A. No. Upward reserves typically impose more costs on a utility's portfolio than downward reserves, although the cost depends on the type of resources in a utility's portfolio. It is often more expensive to hold upward reserves on thermal resources than it is on hydro resources. Conversely, it is often more expensive to hold downward reserves on hydro resources than it is on thermal resources.

Q. WHAT IS THE COST OF DOWNWARD RESERVES?

A. For most utilities with thermal generation, downward reserves can be held at zero cost. Provided that there is sufficient thermal generation online that can be backed down in response to a flexibility down event, no opportunity cost arises from maintaining the online generation levels. Often, downward reserves are ignored altogether in production cost modeling due to the fact that they can be satisfied with no cost from economically dispatched thermal generation resources. Prior to the 2023 AUT, PGE's reserve model, for example, did not consider downward reserve requirements in MONET.

On the other hand, holding downward reserves on hydro resources, as PGE now assumes in MONET, is more expensive than holding downward reserves on thermal resources. As a storage resource, hydro output can be shaped economically to generate more power in high-cost hours and less power in low-cost hours. If generation from a hydro resource is ramped up to hold downward reserves in a low-cost hour, that eliminates power that would otherwise have been available to generate in a high-cost hour, resulting in an opportunity cost to the utility. Therefore, modifying economic hydro dispatch to hold downward reserves is usually only performed as a last resort, as it is a more expensive source of downward reserve capacity than holding downward reserves on thermal resources.

Q. IS THE SAME TRUE FOR UPWARD RESERVES?

A. No. Upward reserves represent an opportunity cost for both thermal resources and hydro resources. If a thermal resource is dispatching economically and a utility is required to ramp down the resource to hold reserves, the utility must purchase power in the market, or forgo a market sale, resulting in higher costs. Considering that the utility also avoids the associated fuel cost, the cost of holding upward reserves on an economic thermal resource can be generalized as the difference between the market prices and the cost of fuel for the generator. In contrast, the cost of holding upward reserves on a hydro resource is often less expensive since any forgone generation can be stored and subsequently used to serve load, albeit potentially at a higher cost.

Q. WHAT IS WRONG WITH PGE'S RESERVES MODELING?

A. PGE's reserve models for hydro and thermal reserves are not integrated. They are performed serially, with hydro reserves allocated prior to thermal reserves and with no co-optimization between the two resource types. Reserves are first allocated to dispatchable hydro resources, and any remaining reserve requirements are then allocated to thermal resources in a second model. Considering the different cost impacts of holding different reserve types on hydro versus thermal resources, this is a major flaw in PGE's reserves modeling method. For upward reserves, the serial approach makes less of difference because it is usually, but not always, less expensive to hold upward reserves on hydro resources prior to holding upward reserves on thermal resources. It makes a significant difference, however, for downward flexibility reserves, including both hour-ahead and day-ahead reserves. It is usually less expensive to hold downward reserves on thermal resources prior to being allocated to hydro resources. As noted above, downward reserves can often be held on thermal resources at no additional cost to the utility. Because of the serial nature of the modeling, however, PGE assigns 100% of downward flexibility reserves to dispatchable hydro resources as the first step in its reserves logic, which is resulting in a distorted system dispatch and overstated NPVC.

Q. HOW DO YOU KNOW THAT THE RESERVES MODEL IS NOT FUNCTIONING AS INTENDED?

A. PGE's reserves modeling results in [redacted] MWh of hydro spill in 2024. Hydro output is valuable and spilling hydro is the most expensive way to hold reserves. Spilling hydro is akin to giving away free power and is therefore an operating measure that utilities avoid. Spilling hydro to generate reserves, for example, would only be resorted to in an emergency. In PGE's model, however, hydro spill is occurring in [redacted] of 366 days of the year. The market value of this spilled energy is worth approximately $[redacted]. This is a clear indication that the MONET reserves modeling is not functioning as intended.

Q. DOES PGE SPILL THAT AMOUNT OF HYDRO IN ACTUAL OPERATIONS?

A. No. In response to AWEC Data Request 93, PGE was not able to identify a single instance where it spilled hydro in order to replenish reserves. The only spill that PGE identified was spill initiated by the Mid-C hydro operators for operational or environmental purposes. While PGE claims that it does not track instances of hydro spill on its own resources, that is hard to believe. Given the cost of spilling hydro power, prudent utility practices otherwise require that instances of hydro spill be tracked for the purpose of being minimized. Based on PGE's response to AWEC Data Request 93, it is apparent that the Mid-Columbia utilities track hydro spill with a high degree of specificity, including instances where PGE would have requested spill for purposes of holding reserves.

Q. WHY IS THE MODEL RESORTING TO SPILLING HYDRO?

A. By allocating all downward flexibility reserves to dispatchable hydro resources, the Mid-Columbia hydro resources must be ramped up uneconomically in every hour of the year, regardless of the market price for power. This not only results in uneconomic hydro dispatch but also reduces the capability of hydro resources to hold upwards reserves. As demonstrated in PGE's response to AWEC Data Request 95, the combination of the Mid-Columbia and the Pelton / Round Butte hydro resources is capable of providing all of the upwards reserves necessary for PGE's operations in most hours of the year. Notwithstanding, ramping up hydro resources to hold downward reserves results in insufficient upward reserve capability necessary to fulfill upward reserve requirements. Due to this faulty logic, these unmet upward reserve requirements are then feeding into the thermal reserves model and ultimately leading to the large volume of hydro spill discussed above. Some of the problem with hydro spill is caused by faults in the thermal reserves model and inaccurate thermal reserve parameters, though given the correction I propose below, it is not necessary to go into the details of those flaws at this time.

Q. IS THE CAPACITY FROM THERMAL RESOURCES SUFFICIENT TO COVER ALL DOWNWARD FLEXIBILITY RESERVES?

A. Yes. The system dispatch of thermal resources already produces enough downward flexibility reserves in every hour, at no incremental system cost, to cover PGE's downward flexibility reserve requirements. Thus, allocating downward flexibility reserves to hydro resources is not necessary.

Q. WHAT CORRECTION DO YOU PROPOSE TO ADDRESS THIS PROBLEM?

A. I recommend that the downward flexibility reserves be allocated first to online thermal resources and allocated to hydro resources only as a last resort. Since online thermal resources can fulfill all the downward flexibility reserve requirements in the study period at no additional cost, I adjusted the flexibility down requirement input into the hydro model to be zero.

Q. HOW DID THIS CHANGE IMPACT NVPC?

A. This change to the MONET reserves logic had a major impact on NVPC. It eliminated all hydro spill and resulted in a more economic dispatch profile than PGE had assumed in its initial filing. As noted above, the impact was a $[redacted] reduction to NVPC. While there are further refinements with PGE's reserves modeling that still need to be addressed in a future proceeding, making this change in this docket will result in a forecast that better corresponds to the actual cost of reserves to PGE.

Q. ARE THERE ANY OTHER ISSUES YOU HAVE IDENTIFIED WITH RESPECT TO DOWNWARD FLEXIBILITY RESERVES?

A. Yes. The EIM manages flexibility reserves. Notwithstanding, utilities are required to meet certain flexibility reserve requirements every hour. Each participating utility is required to meet an hour-ahead flexible ramping sufficiency test and must supply sufficient reserve capacity to meet upward and downward flexible capacity requirements established by EIM. The amount of reserves for each entity is offset by a diversity benefit, since the flexibility reserve requirement for the system as a whole is less than the sum of the flexibility requirements for each of the load-serving EIM entities. PGE provided the actual EIM flexibility reserve requirements in response to AWEC Data Request 96, and based on that response, it is apparent that the amount of downward flexibility reserves included in the MONET model is overstated. This is detailed in Highly Confidential Table 2, below.

Highly Confidential Figure 2
<u>MONET vs. EIM Downward Flexibility Reserves (MW) 2020-2022</u>

[redacted]

In my model, I adjusted the downward reserve requirements to be consistent with the amounts historically calculated by the EIM. Since the higher downward reserve levels PGE assumed could otherwise be held at no cost from online thermal resources, however, this assumption makes no difference to my recommendation.

III. WASHINGTON CLIMATE COMMITMENT ACT

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH PGE'S ADJUSTMENT RELATED TO THE WASHINGTON CLIMATE COMMITMENT ACT.

A. PGE assumes that it has an obligation to comply with the Washington Climate Commitment Act ("CCA").[3] PGE's forecast includes an adjustment to NVPC for sales of power at the Mid-C market hub. To arrive at this adjustment, PGE has asserted that it must purchase Washington CCA allowances for each MWh of power sold at the Mid-C market. This adjustment, however, is flawed in many ways. First, PGE made no effort to evaluate how its thermal plant dispatch will be affected by such a requirement. Second, PGE's forecast assumes that every sale of power at the Mid-C index must be covered by CCA allowances, whereas it is more likely that CCA allowances would only be necessary for a small subset of transactions, if any at all. Third, PGE ignores the complex dynamics of the market price effects associated with the CCA. Sales of power products that are bundled with CCA allowances will demand higher market prices, which will offset the cost of purchasing allowances. Thus, not only is it necessary to remove the Washington CCA adjustment, it is also necessary to adjust the Mid-C index prices downwards to reflect the lower cost for

[3] AWEC will address legal issues and concerns regarding this assumption in legal briefing. Notwithstanding, my testimony should not be interpreted as a concession or waiver of any legal argument that AWEC might raise in briefing.

purchasing power that is delivered outside of Washington State and not subject to the CCA. Finally, I recommend an adjustment that values the additional revenue PGE will be capable of generating by selling non-emitting, specified source power from PGE's hydro and wind resources into the Mid-C market at a premium.

a. <u>Washington Climate Commitment Act Allowance Costs.</u>

Q. WHAT WASHINGTON CLIMATE COMMITMENT ACT COSTS DID PGE INCLUDE IN NVPC?

A. The Washington CCA was passed by the Washington State legislature in 2021. Among other things, the CCA established a "cap and invest" program, which requires certain covered entities to purchase compliance instruments administered by the Washington Department of Ecology ("Ecology") in connection with carbon emissions. Ecology has issued rules implementing the CCA and PGE asserts that it will be required to purchase allowances from Washington to make wholesale sales at the Mid-C market.[4] In its March 31, 2023 update, PGE included $[redacted] of additional costs in its NVPC forecast covering the cost of such allowances in 2024.

Q. HOW DID PGE CALCULATE THIS ADJUSTMENT?

A. PGE assumed it would be necessary to purchase carbon allowances for each MWh of sales it makes at the Mid-Columbia market based on the results of Ecology's February allowance auction. The price of allowances in Ecology's February 2023 allowance auction was $48.50 per metric ton of CO2e ("MTCO2e").[5] The emission factor for unspecified sales is 0.437

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4 PGE/300, Schwartz-Outama-Cristea/30:15-21.

5 State of Washington Department of Ecology, Publication No. 23-02-022, Washington Cap-and-Invest Program Auction #1 February 2023 Summary Report, at 1 (March 7, 2023).

MTCO2e /MWh.[6] Multiplying these values together, the price of allowances for unspecified power is $21.19/MWh, which PGE applied as a reduction to revenues from each sale at the Mid-C market in its NVPC forecast.

Q. DID PGE MODIFY SYSTEM DISPATCH FOR THE ALLEGED CCA ALLOWANCE COSTS?

A. No. PGE is differently situated than Washington utilities that receive free allowances equivalent to the emissions associated with the electricity used to serve their Washington load and administrative costs of the CCA program. In PGE's circumstances, if revenue recognized from each Mid-C sales transaction will be $21.19/MWh less than the market index price, that will have a material impact on how PGE dispatches its system. PGE's adjustment does not capture these offsetting impacts on system dispatch and is therefore inaccurate. For example, some transactions modeled as economic in MONET will no longer be economic and thermal resources would be dispatched more efficiently, reducing costs relative to PGE's adjustment. Conversely, non-emitting hydro resources would be dispatched more heavily in hours when PGE is selling power to the extent those resources can be marketed without requiring the purchase of allowances. These dynamics are material and necessary to consider before assessing any Washington CCA costs to ratepayers.

Q. DOES A CCA COMPLIANCE OBLIGATION APPLY TO ALL TRANSACTIONS AT MID-C?

A. No. The Mid-C market is generally defined based on transactions in the service areas of the three hydro-owning Washington public utilities: Grant PUD, Douglas PUD, and Chelan PUD. As PGE acknowledges, not all transactions at Mid-C will be required to comply with the

6 WAC 173-444-040.

CCA—only transactions with a sink in Washington will be required to be CCA compliant.[7] Further, sales of non-emitting, specified source power would not contribute to a compliance obligation, and therefore, will also not require any allowances. These distinctions are having a major impact on the Mid-C market, which is evolving to include divergent power products to accommodate the CCA.

Q. WHAT NEW PRODUCTS ARE BEING DEVELOPED?

A. Mid-C is a bilateral market trading under the Western Systems Power Pool ("WSPP") Schedule C agreement. Exchange and clearing providers, such as Intercontinental Exchange ("ICE"), also provide a market system to facilitate transactions based on settled market price indexes. In **Exhibit AWEC/103** I have attached notification from PowerEx that describes four distinct Mid-C products surrounding the CCA, including 1) Washington CCA Compliant; 2) Non-Washington Sink; 3) Specified Source, Non-emitting, and 4) Specified Source, Emitting. The first product, Washington CCA Compliant, is a generic power transaction that comes bundled with Washington CCA allowances. The second product, Non-Washington Sink, is a transaction for power exported out of Washington that does not require any purchased allowances. The third and fourth products are for specified power. The PowerEx document describes these generally as a single product, in which the supplier reimburses the purchaser for the cost of Washington CCA allowances, if any, associated with the specified power source. Given the unique characteristics of these products, each will demand a different price in the market. Thus, under this framework, there will no longer be a single market price for power at Mid-C, but rather, differing pricing depending on the type of product supplied.

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[7] PGE/300, Schwartz-Outama-Cristea/29:6-12.

Q. WILL WASHINGTON CCA COMPLIANT POWER PRODUCTS DEMAND A HIGHER PRICE?

A. Yes. The Washington CCA does not change the supply of generation resources nor the demand for power. Therefore, market fundamentals require that a sale of Washington CCA Compliant power products that are bundled with allowances will demand a higher market price than power which does not require allowances, such as Non-Washington Sink products. Assuming the price for an allowance is $21.19/MWh for unspecified power, the price for a sale of a Washington CCA Compliant power products will, all things equal, be $21.19/MWh higher than the cost of power products that do not require allowances. Conversely, a purchase of power that does not require allowances, such as a Non-Washington Sink power product, will demand a price that is $21.19/MWh less than the price for Washington CCA Compliant power products. These market dynamics are complex, and PGE's oversimplified analysis does not consider them.

Q. HOW WILL THE CCA IMPACT THE MID-C MARKET INDICES?

A. Based on **Exhibit AWEC/103**, there is an assumption that the ICE platform index will be based on Washington CCA Compliant power products. Transactions of Non-Washington Sink and Specified Source products will trade bilaterally, off the market index. This means that the market index is inclusive of the cost of purchasing allowances. It also means that transactions of Non-Washington Sink will be traded bilaterally at prices that are less than the price included in the Washington CCA Complaint index. In other words, all power PGE exports from Mid-C will come at a discount relative to the Mid-C index price.

Q. DID PGE CONSIDER ITS ABILITY TO PURCHASE NON-WASHINGTON SINK POWER PRODUCTS AT A DISCOUNT RELATIVE TO THE INDEX?

A. No. Since the power PGE purchases at Mid-C does not sink in Washington, those purchases will be available at a discount relative to the market index price. This is likely one of the reasons why the Mid-C market index is trading so much higher than the cost of generating from gas resources—because the index includes the cost of allowances. Considering this dynamic, it is necessary to adjust the market price index prices assumed in MONET to be reflective of Non-Washington Sink power purchases.

Q. WHAT IS THE IMPACT OF ADJUSTING THE INDEX PRICE TO BE BASED ON NON-WASHINGTON SINK POWER?

A. I reran the MONET model assuming that Mid-C market prices were $21.19/MWh lower than the Washington CCA Compliant market index prices PGE had assumed. This resulted in a $[redacted] reduction to NVPC.

Q. IS IT NECESSARY TO ADD AN ADDITIONAL ALLOWANCE COST FOR MARKET SALES TRANSACTIONS?

A. No. Sales of Washington CCA Compliant, which will require PGE to procure allowances, will demand higher prices relative to the Non-Washington Sink index prices included in my adjusted NVPC calculations. The additional revenues from those sales will directly offset the cost of purchasing allowances. Accordingly, it is necessary to remove the adder to NVPC that PGE forecast with respect to purchasing CCA allowances. This further reduces NVPC by $[redacted]. Thus, properly considering the market impacts of the Washington CCA results in a $[redacted] reduction to NVPC.

b. Specified Source Non-Emitting Sales

Q. WILL PGE BE ABLE TO FURTHER BENEFIT FROM THE CCA?

A. Contrary to assertions that the CCA will represent an additional cost, the CCA is an economic opportunity for PGE to sell specified source, zero carbon power at a premium in the Mid-C market.

Q. DOES PGE HAVE EXCESS NON-EMITTING RESOURCES?

A. Yes. A major portion of PGE's portfolio is from non-emitting hydro and renewable resources. For example, PGE has historically been able to sell all Renewable Energy Certificates ("RECs") from its Wheatridge facility without implicating its RPS obligations. Further, PGE has sufficient hydro generation, including from its Mid-Columbia hydro shares and its Pelton, Round Butte facility, to serve the sales that it makes at the Mid-C market in most hours of the year.

Q. CAN PGE SELL THIS POWER AT A PREMIUM AS SPECIFIED SOURCE, NON-EMITTING POWER?

A. Yes. While it has made little difference in the past, sales of specified source, non-emitting power products will earn a premium in the market because it will not be necessary to acquire any Washington allowances for those products. PGE did not consider this potential benefit of the CCA when proposing the adjustment identified above.

Q. WHAT AMOUNT OF PREMIUM COULD PGE EARN BY SELLING SPECIFIED SOURCE ZERO CARBON POWER?

A. Assuming the same $21.19/MWh premium discussed above, PGE could potentially earn up to $[redacted] in additional revenues by selling specified source, zero carbon energy into the Mid-C market. Recognizing that the opportunity for such sales may only represent a portion of the sales PGE makes, my recommendation is to assume that half of the sales PGE makes in the

Mid-C market are for specified source, non-emitting power, resulting in a total adjustment of $[redacted].

IV. PRODUCTION TAX CREDIT RATE

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE PRODUCTION TAX CREDIT RATE.

A. In its initial filing in this proceeding, PGE forecast a PTC rate of [redacted] cents per kWh, the same value that PGE included in its 2022 AUT filing. As I demonstrate in **Exhibit AWEC/104**, however, the PTC rate, which is set annually based on an index of inflation, will likely increase to 3.0 cents per kWh in 2024, and in no circumstance will the 2024 PTC rate be less than 2.9 cents per kWh. My recommendation is to use a 3.0 cents per kWh rate in this filing, which results in a $[redacted] reduction to NVPC.

Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?

A. The detailed mechanics of the PTC rate were discussed in my Opening Testimony in UE 391 (the "2021 AUT").[8] As noted in that testimony, the IRS adjusts the PTC rate each year by applying an inflation adjustment factor. The inflation adjustment factor is an indexed value calculated based on the GDP implicit price deflator, an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. The Bureau of Economic Analysis publishes the GDP implicit price deflator each quarter, and from that information, the expected GDP implicit price deflator value for calendar year 2023, which will be used to establish the 2024 PTC rate, can be assessed.

[8] Docket No. UE 391, AWEC/100, Mullins/3:12-4:4.

Q. DID THE INFLATION REDUCTION ACT IMPACT THE CALCULATION OF THE PTC?

A. While the Inflation Reduction Act ("IRA") imposes a new PTC rate for new renewable resources placed into service after December 31, 2021, the PTC rate calculation for resources placed into service prior to that date did not change. The IRA PTC rate for new resources is approximately the same as the PTC rate for non-IRA resources, except that it is adjusted in smaller increments, using a slightly different formula.

Q. HOW DID YOU FORECAST THE PTC RATE FOR 2024?

A. In **Exhibit AWEC/104**, I perform a forecast of the PTC rate for 2024 using the same analysis I presented in the 2022 AUT and the 2023 AUT. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for the first quarter of 2023. Based on that publication, it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as inflation equals or exceeds 3.13% on an annualized basis for the remainder of 2023. Given recent indications, it is likely inflation will exceed this level for the remainder of the year. For example, the annualized inflation rate for April 2023 inflation was 4.9%.[9] Further information surrounding the actual inflation rates for 2023, however, will become available as this proceeding progresses.

Q IS THERE ANY CIRCUMSTANCE WHERE THE PTC WILL BE [redacted] CENTS PER KWH?

A. No. Even if one assumes zero inflation for 2023, an impossible scenario given the inflation that has already occurred, the PTC rate will still increase to 2.9 cents per KWh in 2024. Since

9 U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index April 2023 (May 10, 2023) *available at*: https://www.bls.gov/news.release/pdf/cpi.pdf.

inflation is expected to continue to be elevated in 2023, however, I recommend that a 3.0 cents per kWh rate be used in the 2024 AUT.

V. GAS OPTION PLACEHOLDER

Q. DOES PGE'S FILING INCLUDE ANY PLACEHOLDER CONTRACTS?

A. Yes. PGE's filing includes a placeholder gas option contract with a total premium of $[redacted]. As a general principle, PGE is only allowed to include executed contracts in the AUT, and therefore, this placeholder contract is not appropriately considered in this filing. Further, while it is not yet known what type of option agreement PGE might procure, option contracts, in general, are an uneconomic hedging method for ratepayers, and therefore, are not prudent. Finally, if PGE were to execute such an option contract, an extrinsic value adjustment would be necessary that would offset the entire option premium amount. Accordingly, I recommend that this placeholder option be removed from NVPC, and if PGE does enter into such a contract, that it be found imprudent.

Q. WHY ARE OPTIONS CONTRACTS AN UNECONOMIC FORM OF HEDGING FOR RATEPAYERS?

A. Option contracts are an inferior form of hedging relative to traditional hedging products, such as physical forward contracts and financial swaps. Because the NVPC forecast is deterministic, there are no benefits associated with such a contract included in revenue requirement. Yet, ratepayers still must pay substantially more in rates to cover the cost of the option premium—the fixed payment that must be made regardless of whether the option is in-the-money, or not. In contrast, a financial swap provides identical hedging protection against higher prices without the fixed option premium. Swaps are executed based on forward prices at the time of execution, without any need for a lump sum payment in addition to the fixed forward pricing. Because ratepayers can receive the same hedging benefit from a swap at lower cost, option contracts are inherently an imprudent form of hedging.

Q. ARE THERE CIRCUMSTANCES WHERE AN OPTION CONTRACT PROVIDES MORE BENEFIT THAN A SWAP?

A. Option contracts are always a more expensive form of hedging than a swap, except in circumstances when market prices decline by an amount more than the option premium. This is illustrated in Table 3, below.

Table 3
Financial Comparison of Option vs. Swap ($/MMBtu)

		Swap		Option		
Option Premium		-		0.50		
Fixed / Strike		6.00		6.00		
Market		Payout	Net Cost	Payout	Net Cost	Delta
	5.00	(1.00)	6.00	(0.50)	5.50	(0.50)
	5.25	(0.75)	6.00	(0.50)	5.75	(0.25)
	5.50	(0.50)	6.00	(0.50)	6.00	-
	5.75	(0.25)	6.00	(0.50)	6.25	0.25
Forward Price	6.00	-	6.00	(0.50)	6.50	0.50
	6.25	0.25	6.00	(0.25)	6.50	0.50
	6.50	0.50	6.00	-	6.50	0.50
	6.75	0.75	6.00	0.25	6.50	0.50

The illustration in Table 3 compares the net hedged cost of a swap contract to the net hedged cost of an option contract. Both contracts assume an identical fixed/strike price of 6.00/MMBtu, which represents the forward market price. While no option premium is required to purchase a swap at the forward market price, the option contract is assumed to be acquired with an option premium of $0.50/MMBtu. The Net Cost columns equal the cost of purchasing the underlying gas at the ultimate market prices, plus the financial settlements associated with the corresponding hedging instruments.

Under a swap contract, counterparties exchange a fixed monthly price with the floating index price. PGE is paid, or must pay, the difference between the fixed price and the actual market index price. As can be seen in Table 3, if prices go up, PGE receives a financial payment offsetting the increased cost of purchasing gas in the market; if prices go down, however, PGE must make a financial payment to its counterparty. PGE must ultimately procure the underlying gas at whatever the prevailing market price is at the time it is acquired. Accordingly, the net cost to PGE—*i.e.*, the cost of purchasing the gas, less the payout from the swap—is always $6.00/MMBtu. With a swap, PGE pays this same net cost for natural gas regardless of the eventual market price.

The net hedged cost of an option, however, is more complicated. An option contract is asymmetrical and only pays out if market prices exceed a specified strike price, which in this case is assumed to be the forward market price of $6.00. The assumed $0.50/MMBtu option premium must be paid, regardless of whether the option is "in-the-money," or not, at the time of expiration. Thus, the option contract only provides net payout if the market price exceeds the strike price by an amount more than the option premium amount, or $6.50/MMBtu in the example. Thus, if prices go up, ratepayers never pay more than $6.50/MMBtu. This is in contrast to the swap, in which ratepayers never pay more than $6.00/MMBtu. From this perspective, an option contract is an inferior form of hedging because ratepayers always pay more for an option if prices increase.

There are limited circumstances when an option can be more beneficial than a swap. If prices decline by an amount more than the option premium, the option will result in a lower total cost than a swap. In the above illustration, prices must decline to $5.50/MMBtu before the total hedged cost of gas from the option is less than the total hedged cost of gas from the swap. Thus, an option is only beneficial to ratepayers, relative to a swap, if prices decline materially.

Q. IS IT REASONABLE FOR RATEPAYERS TO PAY MORE IN THE AUT BASED ON THE PROSPECT THAT PRICES MIGHT DECLINE?

A. No. Hedging for price reductions is hedging in the wrong direction. Hedging is conducted to protect against the risk of higher-than-expected prices, not the other way around. By making the decision to enter into an option, rather than a swap, PGE is speculating that prices will decline in the forecast period by an amount sufficient to offset the option premiums, which is not prudent.

Q. DOES AN OPTION PROTECT PGE AGAINST PRICE SPIKES?

A. No. While we don't know the terms of the option PGE might propose, an option is typically settled based on average prices over the course of a month. Short-term price spikes that occur in scarcity events may have only minor impacts on the average pricing for the month. Therefore, PGE is better suited to purchase physical gas in order to alleviate the impact of price spikes and scarcity events.

Q. DOES AN OPTION SHIFT RISK OUT OF THE PCAM?

A. Yes. One of the reasons PGE shareholders may desire to enter into an option is that it shifts risk from the PCAM into the AUT. If the option premium is included in the AUT forecast, ratepayers are guaranteed to pay more through Schedule 125, by virtue of the option premiums, while only potentially benefiting in the PCAM if market prices decline. This results in a clear shifting of risk from the PCAM into the AUT. The AUT does not consider the benefit that might be derived from an option if market prices decline. Absent consideration of that benefit, the option contract is not only imprudent, but it is necessary to remove the extrinsic value of the contract from NVPC, consistent with the Commission's decision in UE 181.

Q. DOES THE COMMISSION HAVE A PRECEDENT OF EXCLUDING OPTION PREMIUMS FROM NVPC?

A. Yes. The Commission has a precedent of excluding the extrinsic value of option and super peak products from forecast NVPC. In Docket No. UE 181, PGE's 2007 power cost adjustment filing, the Commission found that "[w]ithout an extrinsic value adjustment, customer rates would include all of the costs, and none of the benefits of the contracts."[10] Since PGE has not actually executed any such contracts for the test period, it is impossible to know the degree of the extrinsic value at issue with the contracts it might execute. If the extrinsic value of the agreements is included in the forecast, ratepayers are irreparably harmed because PGE could have otherwise just acquired gas that would have provided a greater security of supply without increasing NVPC recovered through Schedule 125 rates. Therefore, an adjustment needs to be made to remove the extrinsic value from the forecast to hold ratepayers harmless.

Q. WHAT IS EXTRINSIC VALUE?

A. An option premium is also generally referred to as its extrinsic value, at least for an out-of-the-money option contract such as the one PGE models. The value of a financial instrument is the

[10] Docket No. UE 180 (cons.), Order 07-015 at 13 (Jan. 12, 2007).

sum of its intrinsic and extrinsic value. In the context of NVPC, which is based on current forward market prices, the intrinsic value can be viewed as the benefit of the instrument in the NVPC forecast. The intrinsic value represents the value that can be obtained from the instrument if exercised based on current market prices. For an in-the-money option, the intrinsic value represents the difference between the market price and the strike prices. For an out-of-the-money option, there is no intrinsic value.

The extrinsic value, on the other hand, is the value of everything else, including the option premium. In this case, the terms for the placeholder contract are not known. Since PGE does not model any benefits from the contract, it can be assumed that it is an out-of-the-money contract and that the entire option premium is an extrinsic value.

Q. IS IT APPROPRIATE TO INCLUDE THE EXTRINSIC VALUE OF AN OPTION CONTRACT IN NVPC?

A. No. Regardless of the prudence of the placeholder option contract PGE models, the entire option premium is appropriately removed from PGE's forecast under the precedent established in Docket No. UE 181 identified above.

VI. RELIABILITY CONTINGENCY EVENT

Q. WHAT HAS PGE FORECAST WITH RESPECT TO A RELIABILITY CONTINGENCY EVENT?

A. PGE included a $[redacted] adjustment to NVPC in connection with responding to a contingency event in the forecast period. I recommend this amount be excluded from the NVPC forecast. The AUT is based on a deterministic forecast of median, or normal, conditions. It does not include either the costs when system conditions are constrained or the costs when system conditions are relaxed. Therefore, forecasting a cost associated with responding to a contingency event is one-sided because PGE does not address the benefit of conditions when they are favorable. In addition, PGE's calculation of the cost of a contingency event is flawed in many ways.

Q. WHY IS PGE'S ADJUSTMENT ONE-SIDED?

A. In considering the cost of contingency events, it is also necessary to consider the other side of the distribution, corresponding to beneficial system conditions, such as oversupply events. Based on information provided in PGE's response to AWEC Data Request 81, there were [redacted] hours in which there were negative Mid-C market prices over the period 2020 through 2023. In those hours, PGE was basically being paid to serve its net load requirements. From this perspective, it is not appropriate to include the cost of contingency events in NVPC, without considering the corresponding benefits of the oversupply scenario.

Q. DO YOU AGREE WITH PGE'S CALCULATION OF THE COST OF CONTINGENCY EVENTS?

A. No. PGE compiled a plethora of different cost items in its calculation of the cost of responding to contingency events. PGE's calculations, however, are flawed in at least two different ways. First, the calculation assumes that incremental reserves will be necessary to be held on Beaver, when contingency reserves are already being considered in the reserve forecast assumed in the MONET model. Second, PGE did not correspondingly reduce the amount of reserve held in the MONET model when the contingency event was called. When a contingency event is called, PGE can dispatch resources being held in reserve, which produce power in lieu of purchasing high priced power. Accordingly, calling a contingency event will typically reduce power costs in high-cost days because it frees up generation resources. Given the onesidedness of PGE's adjustment and these issues with its calculation, I recommend that this adjustment be removed from NVPC.

VII. THERMAL PLANT PARAMETERS

a. EIM Master File Parameters

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH PGE'S THERMAL PLANT CHARACTERISTICS?

A. In AWEC Data Request 182, PGE was requested to provide the Western EIM master files submitted over calendar year 2022. PGE only provided one master file that was submitted on December 7, 2022. It is unclear at the time of this writing if there were other files from 2022 that were omitted from PGE's response. In review of those files, there are several material discrepancies between the plant parameters reported to the EIM and those used in MONET. My review was focused primarily on the plant capacities. Highly Confidential Table 4 details several of the discrepancies.

Highly Confidential Table 4
December Maximum Capacities – MONET vs. EIM Master File

	PGE MONET	EIM Master File
Beaver	[redacted]	
Port Westward 1		
Port Westward 2		
Carty		

As can be seen from Highly Confidential Table 4, the maximum outputs for Carty, Port Westward 1, and Port Westward 2 are [redacted] in the EIM master file than in the MONET model. Beaver is also [redacted], but not by the same magnitude as the other resources.

Q. WHAT IS THE IMPACT OF MODELING THE MAXIMUM CAPACITIES FROM THE EIM MASTER FILE?

A. Modeling the capacities identified above results in a $[redacted] reduction to NVPC. Since the master file was submitted in early December 2022, I have assumed the plant capacities to be a December value and shaped the remainder of the months using the same proportions as PGE's filing.

Q. IS THE HISTORICAL DISPATCH OF THE PLANTS CONSISTENT WITH THE INFORMATION REPORTED TO THE EIM?

A. Yes. Carty, instance, had hourly generation as high as [redacted] MWh in the historical data PGE provided in its Minimum Filing Requirements. Port Westward 1 had hourly generation as high as [redacted] MWh.

Q. WHAT DO YOU RECOMMEND?

A. There is no reason for the thermal plant parameters included in the MONET model to be different than the actual plant dispatch parameters reported to the EIM. Accordingly, I recommend PGE explain the differences in plant parameters identified above in its Rebuttal Testimony. For purposes of this testimony, I have assumed an adjustment reflecting the plant parameters in Highly Confidential Table 4.

b. <u>Beaver Cycling</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BEAVER DISPATCH?

A. In MONET, PGE modeling parameters for Beaver do not correspond to how the plant has historically been dispatched. Accordingly, I propose an adjustment to those parameters based on the observed dispatch patterns of the plant.

Q. HOW DOES PGE MODEL BEAVER CYCLING IN MONET?

A. PGE models Beaver as being required to cycle after running a certain number of hours, depending on the month. [redacted].

Q. IS PGE'S MODELING CONSISTENT WITH HOW BEAVER IS ACTUALLY DISPATCHED?

A. No. In actual operations, Beaver runs for extended periods of time without cycling. In **Confidential Exhibit AWEC/105**, I provide duration information surrounding Beaver's cycling profile compared to PGE's assumption in MONET. As can be seen, PGE's modeling assumptions surrounding Beaver cycling are not accurate in comparison to the historical data.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the 90th percentile cycling length identified in Exhibit AWEC/105 be used as the cycling limits modeled in MONET. This value was further adjusted for start-up and shut-down times.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This modification produces an $[redacted] reduction to NVPC.

c. <u>Carty Outage Rate</u>

Q. PLEASE DISCUSS THE ISSUE YOU HAVE IDENTIFIED RELATED TO CARTY OUTAGE RATES.

A. In Docket UE 406, PGE's 2022 Power Cost Adjustment Mechanism, parties filed Joint Testimony demonstrating that an outage at Carty was the result of imprudent actions on behalf of PGE. That proceeding settled with a $1,750,000 black box adjustment to PGE's power cost variance. In response to AWEC Data Request 151, however, PGE confirmed that it did not adjust the Carty outage rate for this imprudent outage.

Q. IS IT APPROPRIATE TO INCLUDE THE 2021 CARTY OUTAGE IN PGE'S NVPC FORECAST?

A. No. The outage was the result of imprudent operations, which were described in Joint Testimony in Docket UE 406. Further, the outage is not the result of normal operating conditions and is appropriately removed as an abnormal outage. Accordingly, I recommend that the effects of the 2021 outage be removed from the Carty forced outage rate used to establish the 2024 NVPC forecast.

Q. WHAT IS THE IMPACT OF REMOVING THE 2021 OUTAGE

A. Removing the 2021 outage from the Carty forced outage rate calculation reduces NVPC by $[redacted].

VIII. BPA WHEELING

Q. WHAT BPA WHEELING ISSUES HAVE YOU IDENTIFIED IN PGE'S FILING?

A. In the stipulation in the 2023 AUT, parties agreed to special treatment for two items related to BPA's transmission rates. First, in Paragraph 9(a)(iv), PGE agreed to return the benefit of a potential BPA Reserves Distribution Clause ("RDC") in this docket.[11] Second, in Paragraph 9(a)(iii), PGE also agreed to defer and return, in this docket, the benefit or cost associated with differences between the assumed and final BP-24 transmission rates.[12] BPA has since issued a transmission RDC, and pursuant to a pre-filing settlement, BPA has also agreed to hold BP-24 transmission rates flat relative to BP-22 rate levels. PGE did not consider these items in its

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11 Docket No. UE 402, Order No. 22-427, Stipulation Appendix A, at 6 (Nov. 1, 2022).
12 *Id.*

filing, and considering the 2023 AUT settlement, they are appropriately considered in this docket. In addition, PGE did not update the going-forward BPA wheeling rates for the BP-24 rate case settlement, a correction which also needs to be applied to PGE's wheeling rate forecast.

a. <u>2023 AUT Stipulation: BPA 2023 Reserves Distribution Clause</u>

Q. PLEASE PROVIDE BACKGROUND ON THE 2023 AUT STIPULATION PROVISION RELATED TO THE RDC.

A. In the 2023 AUT, AWEC filed testimony discussing the mechanics of BPA's Reserves Distribution Clause, which provides a framework for BPA to refund excess reserves to power and transmission customers in certain circumstances.[13] AWEC noted that, given BPA's reserve levels at that time, BPA was likely to issue a RDC to transmission customers for fiscal year 2022, a decision which BPA would announce after the final update in the 2023 AUT. Accordingly, AWEC recommended the benefit of such an RDC be considered after the final NPC update, as a separate adjustment in the 2023 AUT. PGE opposed AWEC's recommendation, stating that BPA was unlikely to issue an RDC.[14] In settlement, however, Parties agreed that the benefit of a potential RDC, if issued, would be deferred and returned to ratepayers in this docket.

Q. DID BPA ISSUE A TRANSMISSION RDC IN 2022?

A. Yes. On December 15, 2022, BPA formally announced a transmission RDC in the amount of $63,100,000.[15] Approximately, $12,900,000 of that amount was to be returned to transmission

[13] Docket No. UE 402, AWEC/100 Mullins/15:7-16:8.
[14] UE 402/PGE/300 Lucas – Outama – Cristea/24:1-2; 16-18.
[15] Bonneville Power Administration, Fiscal Year 2022 Transmission Reserves Distribution Clause Final Decision (Dec. 15, 2022).

customers through a reduction in transmission rates over the ten-month period December 2022 through September 2023. The remainder of the RDC was to be applied to cover other cost items, including towards holding BP-24 rates flat relative to BP-22 rates.

Q. WHAT IS THE IMPACT OF THE RDC ON PGE'S WHEELING COSTS?

A. In response to AWEC Data Request 71, PGE provided a workpaper detailing the reduction in wheeling rates resulting from the 2023 RDC. That workpaper showed that the RDC will result in a [redacted]% reduction to BPA transmission rates over the ten-month period December 1, 2022 through September 30, 2023. In response to AWEC Data Request 71, Highly Confidential Attachment C PGE calculated savings of $[redacted] in connection with the 2023 RDC. This calculation, however, was in error. It assumed the reduced RDC transmission rates would be in effect for 12 months, not the 10-month period BPA approved. Based on the transmission demands included in the final NVPC update in the 2023 AUT, my calculation is the transmission RDC will result in $[redacted] of savings to PGE.

b. <u>2023 AUT Stipulation: BP-24 Wheeling Rates</u>

Q. WHAT DID PGE ASSUME WITH RESPECT TO BP-24 WHEELING RATES IN THE 2023 AUT?

A. In its filing in the 2023 AUT, PGE had forecast an approximate [redacted]% increase to BPA wheeling rates beginning October 1, 2023 corresponding to the rate effective date of the BP-24 rate case. In testimony, AWEC recommended that PGE's assumed BP-24 increase be removed from the 2023 NVPC forecast because it was not known and measurable.[16] In response, PGE argued that a rate increase was likely.[17] In settlement, however, parties agreed to treat the BP-24 rate

[16] Docket No. UE 402 AWEC/100 Mullins/14:16-18; 15:1-3.
[17] UE 402/PGE/300 Lucas – Outama – Cristea/21:1-12.

increase in a manner similar to the 2023 RDC, deferring the difference in BP-24 wheeling expenses relative to the BP-24 transmission rate increase assumed in PGE's filing.

Q. DID BPA PROPOSE AN INCREASE TO TRANSMISSION RATES IN THE BP-24 RATE CASE?

A. No. On December 2, 2022, BPA filed its Initial Proposal in the BP-24 rate case. The BP-24 Initial Proposal was based on a pre-filing settlement reached between BPA and parties, including PGE and AWEC. In the pre-filing settlement, parties agreed to keep transmission rates flat, with no changes, relative to BP-22 rates. This agreement was made in part by agreeing that some of the available RDC funds would be used to offset a potential rate increase. No party is opposing the rates included in the BP-24 pre-filing settlement.

Q. WHAT IS THE DEFERRED IMPACT OF THE BP-24 SETTLEMENT IN THIS DOCKET?

A. Based on the transmission billing determinants assumed in PGE's final update, the impact of the settled BP-24 transmission rates is a $[redacted] reduction to wheeling expenses. In response to AWEC Data Request 71, Highly Confidential Attachment C, PGE calculated $[redacted] of deferred savings in connection with the BP-24 settlement. This calculation, however, also was in error. It appears that PGE did not remove the rate increase it had assumed for scheduling services.

c. <u>BPA 2024 Wheeling Expenses</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO THE BPA WHEELING RATES PGE ASSUMED FOR CALENDAR YEAR 2024?

A. Beginning October 1, 2024, PGE forecast an increase to BPA wheeling rates. BPA's transmission rates, however, are adjusted through a biennial rate case process with the next potential rate change on October 1, 2025. Thus, there is no circumstance in which BPA's rates will increase on October 1, 2024. Further, as noted above, BPA and parties entered into a pre-filing settlement, in which transmission rates were to remain unchanged in the BP-24 rate case, with rate effective October 1, 2023. Thus, the October 1, 2024 wheeling rate increase PGE assumed in MONET is not appropriate.

Q. WHAT BPA RATES DID PGE ASSUME IN THIS DOCKET?

A. PGE used the same transmission rates it had assumed in the 2023 AUT for calendar year 2023, including the [redacted]% fourth quarter rate increase. This may have been an oversight. It is possible PGE overlooked updating BPA transmission rates in its filing. For example, between January 1, 2024 and September 30, 2024, PGE linked to the a cell referencing BP-22 rates, even though BP-24 rates will have already gone into effect, albeit with no rate increase, on October 1, 2023.

Q. IS THERE ANY JUSTIFICATION FOR INCLUDING THE FOURTH QUARTER INCREASE TO TRANSMISSION RATES?

A. No. There is no justification for PGE to forecast an increase to BPA transmission rates in calendar year 2024. Accordingly, I recommend it be removed. Removing this erroneous BPA rate increase will result in a $[redacted] reduction to NVPC.

IX. BIGLOW GENERATION

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BIGLOW'S GENERATION?

A. It was well documented in the press that PGE had wind turbine failures at its Biglow wind facility in 2022. An article in the Oregonian discussing the incidents and PGE's response is attached as **Exhibit AWEC/106**.

Q. HOW DO YOU RECOMMEND HANDLING THOSE FAILURES IN THIS CASE?

A. AWEC recommends that 2022 be excluded from the capacity factor calculation for Biglow. The abnormal events that occurred in 2022 were not only the results of imprudence, but not indicative of the plant operations going forward.

Q. WHAT IS THE IMPACT OF EXCLUDING 2022 FROM BIGLOW'S CAPACITY FACTOR CALCULATION?

A. Excluding 2022 from Biglow's capacity factor calculation produces a $[redacted] reduction to NVPC.

X. BALANCING ADJUSTMENT

Q. PLEASE EXPLAIN THE BALANCING ADJUSTMENT IN CONFIDENTIAL TABLE 1.

A. Each of the NPC impacts in this testimony were calculated as one-off adjustments, without considering the impacts of any other adjustments. This was done to isolate the impacts of individual modeling changes, without having the impacts skewed by the order in which the adjustment calculations were performed. There are, however, counterbalancing impacts between different adjustments. The impact of the Carty outage rate adjustment, for example, is different if one uses the higher maximum capacity from the EIM master file than if one uses the maximum capacity from PGE's filing. As another example, allowing for longer cycling of Beaver has a greater impact if reserve allocations are corrected in the downward flexibility reserve adjustment. To account for these counterbalancing impacts, as a last step in my modeling, a MONET model run was prepared that consolidates all of the adjustments described in testimony. The balancing adjustment is the difference between the sum of the individual adjustments and the consolidated MONET model study. In this case, the consolidated study resulted in an additional $[redacted] reduction to NVPC due to the nature of the adjustments at issue.

Q. DOES THIS CONCLUDE YOUR OPENING NVPC TESTIMONY?

A. Yes.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1305

Docket No. UE 420
AWEC Discovery Responses to PacifiCorp

September 1, 2023

<u>PACIFICORP DATA REQUEST NO. 5 TO AWEC:</u>

For the following questions: Please Refer to AWEC/100, Mullins/4, Section III. HUB Demands.

a. Does AWEC believe that the absence of market caps within the NPC forecast will bring the Company closer to accuracy in its forecast of market sales? If yes, please explain how AWEC envisions that this increase in forecast accuracy will be achieved.
b. On line 21, Mr. Mullins states that Aurora does not optimize sales and purchases in the same way as GRID. Please elaborate on the differences between Aurora and GRID's least-cost optimization, specific to any area in which AWEC believes that Aurora's least-cost optimization is outperformed by GRID's least-cost optimization.

RESPONSE TO PACIFICORP DATA REQUEST NO. 5:

a. AWEC has not formed a position on this question. For its position in this docket, please refer to the referenced testimony.
b. AWEC does not necessarily agree that the AURORA model produces a least-cost optimization. AWEC's analysis of removing the Palo Verde market from AURORA resulted in an increase to NPC. This indicated that the model is not fully optimized as imposing an additional constraint on a least-cost optimization would theoretically never increase costs if the model were fully optimized. AWEC is still evaluating this deficiency in the model.

Date: July 10, 2023
Respondent: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 9 TO AWEC:

Please refer to AWEC/200, Mullins/41, lines 21 – 23. Please provide calculations supporting the derivation of the stated annualized inflation rates of 6.418% and 6.409%, using the GDP implicit price deflator for calendar years 2021 and 2022, respectively.

RESPONSE TO PACIFICORP DATA REQUEST NO. 9:

Please refer to WIEC Exhibit No. 202.8. The referenced values were calculated by comparing the Q4 implicit price deflators of 2021 and 2022 to the previous year. The 2021 value was calculated by dividing 121.71 (the 2021 Q4 implicit price deflator) by 114.37 (the 2020 Q4 implicit price deflator). Similarly, the 2022 value was calculated by dividing 129.51 (the 2022 Q4 implicit price deflator) by 121.71 (the 2021 Q4 implicit price deflator).

Date: August 29, 2023
Respondent: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 10 TO AWEC:

Please refer to AWEC/200, Mullins/42, lines 1 – 2. Please provide a workpaper with calculations intact supporting the assertion that "historically Core PCE Inflation has been approximately 1.6% less than the inflation rate measured using the GDP implicit price deflator."

RESPONSE TO PACIFICORP DATA REQUEST NO. 10:

As noted in the federal reserve release identified in the footnote of the referenced sentence, actual Core PCE inflation was 4.7% and 4.8% in 2021 and 2022, respectively. The approximate 1.6% value was calculated by comparing those actual values to the 6.418% and 6.409% GDP Implicit Price deflator inflation for 2021 and 2022, respectively, as identified in the sentence preceding the referenced sentence. Note that the 1.6% was an approximation, as the average difference between the two inflation values during the two years was approximately 1.66%

Date: August 29, 2023
Respondent: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 12 TO AWEC:

Refer AWEC/200, Mullins/2, Table 1. For any values in this Table 1 derived using Aurora, please specify the version or versions of Aurora used.

RESPONSE TO PACIFICORP DATA REQUEST NO. 12:

AWEC Witness Mullins used Aurora version 14.2.1052.

Date: August 29, 2023
Respondent: Bradley G. Mullins

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1306

Docket No. UE 296 ICNU/200
Cross-Answering Testimony of Bradley G. Mullins (redacted version)

September 1, 2023

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2016 Transition Adjustment Mechanism.	)
	)
____	)

REDACTED CROSS-ANSWERING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 3, 2015

I. INTRODUCTION

Q. ARE YOU THE SAME BRADLEY G. MULLINS THAT FILED OPENING TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Opening Testimony on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Pacific Power ("PacifiCorp" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to the Opening Testimony of Jorge Ordonez on behalf of Staff, Bob Jenks and Nadine Hanhan on behalf of the Citizens' Utility Board of Oregon ("CUB"), and Kevin Higgins on behalf of Noble Americas Energy Solutions LLC ("Noble Solutions"). In addition, my testimony describes known updates and corrections to the net power cost ("NPC") adjustments presented in my Opening Testimony.

Q. PLEASE PROVIDE A SUMMARY OF THE UPDATES AND CORRECTIONS TO YOUR OPENING TESTIMONY.

A. The updates and corrections to my Opening Testimony are as follows:

- The adjustment titled "2a: Reserves - Regulation Correction" is withdrawn. Based on representations from the Company, the reserve contracts in question were intentionally allowed to provide a level of reserves in excess of the load following reserve requirements, because the Generation and Regulation Initiative Decision Tools ("GRID") model was also using the reserves from those contracts to offset contingency reserve requirements. Therefore, no correction was necessary.

- The hourly reserve calculations developed using 90% exceedance[1/] in adjustment "2b: Reserves - Reliability Metric" were updated to reflect a minor correction. The wind following reserves in the month of March incorrectly referenced a file containing February reserve values. The impact of this correction is an approximate $37,918 reduction to the adjustment value.
- The adjustment related to the Hermiston point-to-point ("PTP") contract was updated to reflect six months of contract payments. Previously, the adjustment value was calculated based on one month of contract payments; however, because the Hermiston purchase contract expires in July of 2016, six months of payments should have been included in the calculation. In addition, while I did not recommend so in my Opening Testimony, the Company should also remove the transmission capacity associated with the Hermiston PTP contract from the GRID model transmission topology. Removing the capacity associated with the portion of the PTP contract attributable to the Hermiston purchase contract will result in an increase to NPC modeled in GRID, which should be applied as an offset to this adjustment in the Company's final GRID model runs. My GRID modeling does not reflect this offset.

Q. HAVE YOU PREPARED AN UPDATED TABLE TO ACCOUNT FOR THESE CORRECTIONS AND UPDATES?

A. Yes. Table 1-CA, below, includes the impact of each of these updates and corrections, with the corrected adjustments indicated in italics.

[1/] Note that for purposes of Opening Testimony the term used to describe the reliability metric was "confidence interval," which is often used interchangeably with exceedance-based statistical intervals. Notwithstanding, the more technically correct term to describe the statistical interval used by the Company is likely a "predictive confidence interval" or "prediction interval."

TABLE 1-CA
Updated NPC Recommendation

	$000	
	Total-Company	Oregon-Allocated
2015 TAM	1,472,643	363,705
Company Filing	1,537,484	374,516
NPC Increase	64,842	10,811
Other Revenue Adjustment	8,803	2,296
EIM Costs Reduction	(2,088)	(547)
Load Adjustment	-	(808)
Company Proposed Rate Increase	**71,557**	**11,752**
Recommended Adjustments:		
1a Reject System Balancing Adj.	(31,300)	(7,739)
1b Market Liquidity Proposal	(6,862)	(1,697)
2a *Reserves - Regulation Correction*	-	-
2b *Reserves - Reliability Metric*	*(11,202)*	*(2,770)*
2c Reserves - PSE & APS Reserve Diversity	(61)	(15)
2d Reserves - Idaho Power Asset Exchange	(1,327)	(328)
3a EIM Disp. Benefit - Seasonality	(1,471)	(364)
3b EIM Disp. Benefit - New Participants	(3,158)	(781)
4b *Hermiston - PTP Contract*	*(2,637)*	*(652)*
5 Outage Modeling	(789)	(195)
6a Wind Profile - Avian Protection	(211)	(52)
6b Wind Profile - Rolling Average	(5,758)	(1,424)
Total Adjustments	(64,775)	(16,015)
Recommended Rate Increase (Decrease)	**6,782**	**(4,263)**

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT TABLE 1-CA?

A Yes. The adjustments in Table 1 in my Opening Testimony were performed sequentially and the order of the runs impacted the ultimate adjustment amount. For purposes of the above updates and corrections, I did not rerun each of the studies to reflect the potential impact of the update on the other adjustments. These adjustments also do not reflect the thermal plant screening process, a lengthy manual process undertaken by the Company to determine which plants to run in the model on an hourly basis. Accordingly, the ultimate impact of each adjustment on NPC may be slightly different when the Company reruns NPC based upon the methodologies approved by the Commission in its November update.

Q. HAVE YOU REFINED ANY OF THE RECOMMENDATIONS DETAILED ABOVE?

A. Yes. I recently filed testimony before the Wyoming Public Service Commission ("Wyoming PSC") on behalf of the Wyoming Industrial Energy Consumers in Wyoming PSC Docket No. 20000-469-ER-15 (the "Wyoming GRC"). In that proceeding, I recommended a slightly different methodology for determining the shape of Energy Imbalance Market ("EIM") inter-regional dispatch benefits. Based on my review of the Company's updated calculations of EIM benefits presented in that proceeding, I concluded that the economic margins on inter-regional EIM transfers were better aligned with changes to the overall market prices, rather than changes in the market spreads between the Northwest and California. This updated calculation resulted in a larger adjustment value of approximately $3 million in that proceeding. Because, however, the Company has not presented an updated calculation of inter-regional EIM dispatch margins in this proceeding, and due to the fact that updating the methodology would result in a larger adjustment, I have not updated my recommendation for purposes of this proceeding.

In addition, in the Wyoming GRC, I did not address the Company's proposal to update the capacity factors of non-owned wind resources. I continue, however, to believe that the use of a five-year period to normalize the output from these resources is too short to be used to establish normalized NPC and have not withdrawn that adjustment for purposes of this proceeding.

II. RESPONSE TO STAFF

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF STAFF'S TESTIMONY.

A. Staff's testimony makes three recommendations. First, Staff proposes to model dynamic transfer capability between balancing areas.[2/] Second, Staff recommended including within-hour dispatch benefits as an EIM adjustment.[3/] Third, Staff recommends that the Commission reject the Company's proposed system balancing adjustments.[4/]

Q. DO YOU AGREE GENERALLY WITH STAFF'S RECOMMENDATIONS?

A. Yes. Staff's recommendations largely overlap with recommendations made in my Opening Testimony. Staff's first proposal, to model dynamic transfer capability between balancing areas, is similar in concept to my adjustment "2d: Reserves - Idaho Power Asset Exchange," where I have modeled the ability of the Company to transfer 50 MW of capacity between the Eastern and Western Balancing Areas. Staff's second proposal, regarding EIM within-hour dispatch benefits, largely overlaps with my adjustment "2b: Reserves - Reliability Metric," which was premised in part on the notion that relaxing the confidence interval in the reserve study would be more reflective of the within-hour reserve savings expected from the EIM. Finally, Staff's third proposal is consistent with my adjustment "1a: Reject System Balancing Adj.," to reject the Company's proposed modeling adjustment to reflect historical system balancing costs. As a result, I generally agree with the recommendations made by Staff in Opening Testimony.

2/ Staff/100 at 2:8-9.
3/ Staff/100 at 2:10-11.
4/ Staff/100 at 2:12-13.

Q. PLEASE EXPLAIN.

A. In the matter of dynamic transmission transfer capability between balancing areas, for instance, Staff and ICNU both note that the Company has failed to model benefits associated with 200 MW of additional operational flexibility between its balancing areas resulting from an approved asset exchange with Idaho Power Company.[5/] While Staff firmly believes that "such benefits should be reflected in this filing,"[6/] Staff did not offer a definite adjustment in opening testimony, explaining that it "continues to explore this issue."[7/] ICNU fully agrees that such benefits should be reflected in this case, in support of which I have provided testimony recommending a $0.3 million NPC reduction on an Oregon-allocated basis.[8/] Similarly, another Staff recommendation, that the Commission not adopt the Company's proposed system balancing modeling change,[9/] is complemented by ICNU's recommendation that the Commission reject the Company's system balancing adjustment in conjunction with the adoption of an alternative modeling change to incorporate realistic bid-ask spreads in the Company's GRID model.[10/]

Q. WOULD YOU LIKE TO ADD ANYTHING IN REGARD TO STAFF'S OPENING TESTIMONY?

A. Yes. Staff has proposed a $1.43 million Oregon-allocated reduction to NPC to account for the EIM benefits of reduced regulating margin reserve resulting from within-hour scheduling.[11/] I believe that Staff's proposed adjustment has merit, and complements ICNU recommendations

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5/ Compare Staff/100 at 8-11, with ICNU/100 at 31-33.
6/ Staff/100 at 11:3-4.
7/ Id. at 10:11-12.
8/ ICNU/100 at 31-33.
9/ Staff/100 at 20-24.
10/ ICNU/100 at 5-20.
11/ Staff/100 at 15:18-16:10.

to account for these EIM benefits through a holistic review of the Company's reserve study and the use of a 90% exceedance interval.[12/]

III. RESPONSE TO CUB

Q. DO YOU AGREE WITH CUB'S CHARACTERIZATION OF THE COMPANY'S SYSTEM BALANCING PROPOSAL?

A. Yes. CUB notes that the Company's system balancing modeling proposal in this proceeding is premised largely on the notion that actual NPC in recent years has been higher than the level of normalized NPC established in the TAM.[13/] CUB suggests that the Company's use of historic variation between normalized and actual NPC in its modeling "is a significant and inappropriate change."[14/] I agree. In my Opening Testimony, I explained that the Company's reliance upon extraordinary weather and market conditions in 2014 produced an unreasonable result in the Company's bid-ask spread calculations, leading me to recommend that "the impact of historical weather events should be normalized out of power costs."[15/] Similarly, CUB points out that the fundamental design of the TAM is "to forecast power costs on a weather normalized basis. It was not intended to reflect the actual prices incurred under actual weather conditions."[16/]

Q. IS THE GRID MODEL INTENDED TO PERFECTLY FORECAST ACTUAL NPC?

A. No. The GRID model is a tool that is used to develop normalized levels of NPC, based upon normal loads, normal prices and known and measurable changes to the Company's resource portfolio. The GRID model, itself, is not intended to produce a perfect forecast of the level of NPC that the Company will experience in actual operations. Actual NPC is ultimately driven

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12/ ICNU/100 at 23-31, 33-39.
13/ CUB/100 at 5:11-7:22.
14/ CUB/100 at 1:11-12.
15/ ICNU/100 at 18:8-15.
16/ CUB/100 at 2:21-23.

by the Company's success in managing NPC on a daily basis and a number of other factors such as weather conditions, market conditions, unforeseen changes in the Company's resource portfolio, and plant availability. Some of these anomalies, such as weather conditions, are removed from the level of normalized NPC included in rates, as they are not representative of known and measurable test period conditions.

Q. DO YOU AGREE THAT THE GRID MODEL UNDERSTATES NORMALIZED NPC?

A. No. The recent differences between normalized NPC and actual NPC have no bearing on how effective the GRID model is at calculating a normalized level of net power costs. The difference between the level of normalized NPC included in rates and actual NPC is ultimately driven by the accuracy of the forecast inputs into the model—the loads, forward prices, and forecasted changes to the Company's resource portfolio. If, for example, the Company's load forecast is understated in the GRID model relative to actual operations, the resulting increases in actual NPC should not be construed as an indication that the GRID model, itself, produces an inaccurate calculation of normalized NPC. Rather, it should be construed as an indication that the normalized load input into the model was inaccurate. Similarly, if the forward prices input into the GRID model are materially different from the prices experienced in actual operations, it is expected that actual NPC will be also be materially different from the Company's forecast. Thus, the difference between normalized and actual NPC is an indication that inputs into the model did not correspond to actual weather and plant conditions that occurred in the test period, not that the GRID model produced an inaccurate normalized forecast.

Q. WHY HAS THE COMPANY'S ACTUAL NPC BEEN HIGHER THAN NORMALIZED NPC IN RATES IN RECENT YEARS?

A. A combination of factors have led to the Company's high power costs in 2013 and 2014, relative to normalized base NPC. Foremost, the weather conditions in the Northwest have been abnormal in recent years. Due to extraordinarily cold temperatures in the winter of 2013 – 2014, power prices at certain Northwest power hubs were trading at hundreds of dollars per megawatt-hour. In addition, the Company experienced several plant outages during this period, including major outages at Colstrip Unit 4, Chehalis, and Wyodak. The combination of these factors led to some of the highest levels of monthly NPC that the Company has experienced since the California energy crisis in 2001. The 2014 – 2015 winter, however, has not resulted in such extraordinary conditions. As detailed in Confidential Figure 1-CA, below, the NPC in the 2014 – 2015 winter timeframe has been materially lower than the NPC experienced by the Company in the 2013 – 2014 winter.

CONFIDENTIAL FIGURE 1-CA
Year-to-Year Comparison of Winter NPC ($million)

[redacted]

Q. WHAT IS THE PROPER WAY TO EVALUATE THE ACCURACY OF THE GRID MODEL?

A. One of the only ways to fairly understand how accurate the GRID model is in producing a normalizing NPC relative to matters outside the Company's control (like weather) is to perform a "back-cast." A back-cast is a model run that is populated with inputs representative of the Company's actual operations over a historical period. For purposes of the GRID model, this would include using actual loads, actual prices, and other aspects of the Company's actual resource portfolio in the historical period. The expectation is that the GRID model, if populated with the non-normal actual data associated with the historical period, will produce a level of NPC that is consistent with actual NPC in a historical period. To be adequate, a back-cast should be performed over a number of years, and include varying market and resource conditions.

Q. DID THE COMPANY PREPARE A BACK-CAST TO SUPPORT ITS CLAIMS THAT THE GRID MODEL INACCURATELY NORMALIZES NPC?

A. No. Absent a back-cast or other similar analysis that would isolate the impact of non-normal conditions on power costs, I disagree with the Company's claim that the GRID model, as it has been deployed, systematically understates normalized NPC.

Q. HAS THE COMPANY PERFORMED A BACK-CAST IN THE PAST?

A. Yes. My understanding is that the Company has, in fact, performed a number of back-casts since the GRID model was developed in 2001 and that these studies have demonstrated that the GRID model does produce an accurate level of normalized NPC. The Company prepared a back-cast in 2003 shortly after the GRID model was implemented.[17/] As stated by Randy Falkenberg, who reviewed the Company's back-cast analysis on behalf of ICNU, "[i]n the

[17/] See, e.g., In re Pacific Power Light Request for a General Rate Increase in the Company's Oregon Annual Revenues, Docket No. UE 170, Surrebuttal Testimony of Randall J. Falkenberg, ICNU/111 at 24:13-24.

analysis, the Company contended that GRID predicted power costs within 0.1% of actual."[18/] The Company has not performed a similar analysis in this proceeding. Thus, it is not possible to know whether, as a result of some structural change in the Company's operating environment, the GRID model no longer produces accurate normalized results as it once did.

Q. DO YOU AGREE WITH CUB'S CONCLUSION THAT THE COMPANY'S PROPOSED MODELING WOULD IMPROPERLY RESULT IN THE INCLUSION OF HISTORICAL NON-NORMAL COSTS IN NPC?

A. Yes. The evidence is clear that the Company's modeling proposal is heavily influenced by historical market and weather anomalies. For example, the excessive market spreads in February detailed in Confidential Table 2 of my Opening Testimony were driven largely by the extraordinary power costs experienced by the Company in February of 2014, detailed in Confidential Figure 1-CA above.

Q. DO YOU AGREE WITH CUB'S PROPOSALS REGARDING THE EIM?

A. CUB's testimony on EIM benefits is consistent with ICNU's recommendations in many respects. For instance, both parties point out the need to account for seasonality, while CUB has stated an openness to accept benefit forecasting results that differ from the Company's.[19/] As CUB observes in regard to the EIM: "The Company's reality is changing. How they operate will change."[20/] In this light, I recommend that the Commission take into consideration the recent treatment of EIM benefits by other state commissions regulating the Company.

Q. HOW HAVE OTHER STATE UTILITY COMMISSIONS TREATED EIM BENEFITS ACCRUING TO THE COMPANY?

A. The Wyoming PSC rejected claims that EIM benefits were too uncertain to incorporate into rates established in 2014, finding that the Company "provided little comfort that it would be

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18/ Id.
19/ Compare CUB/100 at 8-9, with ICNU/100 at 35-39.
20/ CUB/100 at 10:5.

able to calculate benefits as the EIM progresses."[21/] Like CUB, the Wyoming PSC effectively recognized that "[t]he Company's reality is changing" via EIM participation, and would not allow customers to be deprived of definite rate period benefits, simply on account of any imperfect benefit forecasting analysis supplied by the Company.

Conversely, within just three months of finding that EIM benefit estimates were "too uncertain" in the Company's recent general rate case,[22/] the Washington Utilities and Transportation Commission ("WUTC") had to open a new EIM investigatory docket in June 2015 to obtain "information concerning the estimated benefits to Pacific Power and its Washington ratepayers from participation in the EIM."[23/] The WUTC's initial acceptance of the Company's claim—i.e., that it was "impossible … to accurately project the amount of offsetting benefits" related to the EIM in 2015[24/]—has resulted in Washington ratepayers being deprived of current EIM benefits in conjunction with the unnecessary resource drain of additional and avoidable proceedings. This outcome can be averted in Oregon simply by following the example of the Wyoming PSC in accounting for all reasonably proposed EIM benefits in the present docket.

Q. SHOULD THE COMPANY BE REQUIRED TO DEFER THE DIFFERENCE BETWEEN ACTUAL EIM BENEFITS AND THOSE BENEFITS FORECAST IN THE TAM, AS SUGGESTED BY CUB?

A. Irrespective of whether there is a deferral to account for variances between forecast and actual EIM benefits, it is important to set the base level of EIM benefits in a manner that is as accurate as possible. While I do not take issue with CUB's deferral proposal in this

21/ Re Application of Rocky Mountain Power for Approval of a General Rate Increase, Wyoming PSC Docket No. 20000-446-ER-14, Order at ¶ 184 (Dec. 30, 2014).

22/ WUTC v. Pacific Power, WUTC Dockets UE-140762 *et al.*, Order 08 at 89 (Mar. 25, 2015).

23/ Re Investigation of Pacific Power and Light Company's Participation in the Energy Imbalance Market, WUTC Docket UE-151273, Notice of Opportunity to File Written Comments and Notice of Workshop (July 10, 2015).

24/ WUTC Dockets UE-140762 *et al.*, Duvall, Exh. No. GND-4T at 30:22-23.

proceeding, I would note that the Company already has the Power Cost Adjustment Mechanism, where the EIM benefits will be trued-up.

IV. RESPONSE TO NOBLE SOLUTIONS

Q. ARE YOU CONCERNED WITH ANY OF THE PROPOSALS MADE BY NOBLE SOLUTIONS IN OPENING TESTIMONY?

A. No. Noble Solutions has made recommendations concerning direct access transition adjustments and opt-out issues, which appear reasonable and desirable in order to avoid potential draconian results that would not be in keeping with the purpose of Oregon's direct access law. With members who could be affected by these direct access issues, ICNU supports the adoption of Noble Solutions' opening testimony recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1307

Docket No. UE 323
Excerpt of August 31, 2017 Hearing Transcript

September 1, 2023

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UE 323**

In the Matter of:

**PACIFICORP, dba PACIFIC POWER,
2018 Transition Adjustment Mechanism**

HEARING

**HELD ON
THURSDAY, AUGUST 31, 2017
9:30 A.M.**

**BEFORE THE HONORABLE
SARAH ROWE, ADMINISTRATIVE LAW JUDGE**

**PUBLIC UTILITY COMMISSION
HEARING ROOM
201 HIGH STREET SOUTHEAST
SALEM, OREGON 97301**

**REPORTED BY:
KIM MCLAIN
NAEGELI DEPOSITION AND TRIAL
111 SOUTHWEST FIFTH AVENEUE, SUITE 2020
PORTLAND, OREGON 97204**

APPEARANCES

APPEARING FOR PUBLIC UTILITY COMMISSION:

LISA HARDIE, CHAIR
MEGAN W. DECKER, COMMISSIONER
STEPHEN M. BLOOM, COMMISSIONER

APPEARING ON BEHALF OF STATE OF OREGON:

SOMMER MOSER, ESQUIRE
Oregon Department of Justice
1162 Court Street, NE
Salem, Oregon 97301
(503) 947-4548
(503) 378-6424 (Fax)
sommer.moser@doj.state.or.us

APPEARANCES CONTINUED

APPEARING ON BEHALF OF PACIFICORP:
KATHERINE MCDOWELL, ESQUIRE
ADAM LOWNEY, ESQUIRE
McDowell Rackner & Gibson PC
4I9 SW 11TH Avenue, Suite 4OO
Portland, Oregon 97205
(503) 595-3926
(503) 595-3928 (Fax)
katherine@med-law.com
adam@med-law.com

APPEARING ON BEHALF OF CALPINE SOLUTIONS:
GREGORY M. ADAMS, ESQUIRE
Richardson Adams, PLLC
515 N 27th Street,
Boise, Idaho 83702
(208) 938-7900
(208) 938-7904 (Fax)
greg@richardsonadams.com

APPEARANCES CONTINUED

APPEARING ON BEHALF OF INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES (ICNU):

JESSE E COWELL, ESQUIRE
Davison Van Cleve
333 SW TAYLOR Street, Suite 400
Portland, Oregon 97204
(503) 866-6633
(503) 241-8160 (Fax)
jec@dvclaw.com

APPEARING FOR CITIZENS UTILITY BOARD (CUB):

MICHAEL GOETZ, ESQUIRE
BOB JENKS, EXECUTIVE DIRECTOR
Oregon Citizens' Utility Board
610 SW Broadway, Suite 4OO
Portland, Oregon 97205
(503) 227-1984
(503) 224-2596 (Fax)
mike@oregoncub.org

APPEARANCES CONTINUED

APPEARING TELEPHONICALLY ON BEHALF OF SIERRA CLUB:

TRAVIS RITCHIE, ESQUIRE
2101 Webster Street, Suite 1300
Oakland, California 94612
(415) 977-5500
travis.ritchie@sierraclub.org

(Whereupon, Public Session resumes.)

ALJ ROWE: So Mr. Mullins, if you would please come to the stand.

Please raise your right hand.

BRADLEY G. MULLINS, called as a witness on behalf of the ICNU, having been first duly sworn, was examined and testified as follows:

THE WITNESS: Yes.

ALJ ROWE: And please state your name for the record.

THE WITNESS: Bradley G. Mullins.

ALJ ROWE: Mr. Cowell, do you have any preliminary matters for Mr. Mullins?

MR. COWELL: Yes, Your Honor. Thanks.

DIRECT EXAMINATION

BY MR. COWELL:

Q. Mr. Mullins, could you please state your affiliation with ICNU?

A. I'm an independent consultant that represents ICNU throughout the Northwest.

Q. Okay. And in that capacity, did you file testimony and exhibits in this proceeding?

A. I did.

Q. And were those opening and rebuttal and Cross-examination Exhibits 100 through 104 and 200

through 202?

A. Yes, they were.

Q. And Mr. Mullins, do you have any changes or corrections to make?

A. Just some minor changes. So in ICNU/100 on page 8, line 3.

ALJ ROWE: Hold on a second. Okay.

THE WITNESS: All right. So ICNU/100, page 8, line 3, the -- it states the 2017 TAM forecast of the Company. And that should read the 2016 TAM forecast of the Company.

Then continuing with the same piece of testimony on page 11, line 17, it refers to Exhibit No. ICNU-103, and that should be ICNU-104. And then in my rebuttal testimony, ICNU/100, page 2, line 3, I state -- I quote a number, 380.4 million, and that should actually be 370.2 million, and the Footnote No. 1, should also be changed.

ALJ ROWE: Wait. Where is the 300 --

THE WITNESS: On line number 3.

ALJ ROWE: Page?

THE WITNESS: Oh, page 2.

ALJ ROWE: Okay. Three what?

THE WITNESS: 370.2 is the number.

ALJ ROWE: Okay.

THE WITNESS: Then the footnote should be corrected to refer to PAC/400 at page 4, line 22 through page 5, line 1.

ALJ ROWE: PAC/400 at what line? Sorry. Or page?

THE WITNESS: Page 4, line 22 --

ALJ ROWE: Page 4, line 22.

THE WITNESS: -- through page 5, line 1.

ALJ ROWE: Page 5, line 1. Okay.

THE WITNESS: And that's it.

MR. COWELL: Your Honor, thank you. The witness is available for cross.

ALJ ROWE: Thanks. Okay. Does Staff or the Company -- does Company want to start? Staff usually goes last.

MR. LOWNEY: Yeah, I'd be happy to.

CROSS-EXAMINATION

BY MR. LOWNEY:

Q. Good afternoon, Mr. Mullins.

A. Good afternoon.

Q. For the record, my name is Adam Lowney, counsel for PacifiCorp. If we could start -- if you could turn to -- well, actually, let me just ask a preparatory question about your adjustments in this case. Now, PacifiCorp has calculated the day-ahead

and real-time adjustment using five years of historical data; is that correct?

A. That's my understanding, yes.

Q. And you recognize that that adjustment calculated using only two years of data, 2015 and 2016; is that correct?

A. Correct.

Q. Now, if you could turn to your direct testimony, please, that's ICNU/100, page 13.

A. Did you say page 15?

Q. 13.

A. 13. Okay.

Q. And on lines 8 to 9, you testified your proposed change is appropriate because the Company has clearly made some changes in the way it balances its system since it began participating in the EIM. Do you see that testimony?

A. I do.

Q. Now, CUB made the same argument in last year's TAM, correct?

A. I -- I think you have to ask CUB that question. I --

Q. Mr. Mullins, you were a witness in last year's TAM, correct?

A. Correct. I'm not aware of the extent that

CUB made an argument and all their arguments. I -- they may have made an argument similar to the argument I made, but I'm sure they weren't exactly the same.

Q. Now, are you familiar with the Commission's order in last year's TAM, that would be Order 16-482?

A. I'm not intimately familiar with that order.

Q. Okay. On page 12 of that order it says that CUB argued the PacifiCorp's volume adjustment improperly uses pre-EIM data. Now, is that basically your argument here as well?

A. Well, so, you know, my argument's a little bit different and --

Q. Well, I'm asking you a question. Did you -- do you argue that the Company should not use pre-EIM data?

A. Well, my argument was a little bit different in what was described there so -- and I would be happy to discuss that if -- if you --

Q. Well, I just need to ask you if you recall the Commission did not -- excuse me, the Commission rejected CUB's adjustment of last year's TAM, correct?

A. Sure. If it's in the order.

Q. Okay.

ALJ ROWE: I'm going to ask Mr. Mullins to explain his argument, because it gets too confusing for me to not have him explain it, and then you talked about someone else's adjustment. So you can go and ahead answer the question for me.

THE WITNESS: So it actually relates to more than the confidential Table 2, which is on page 12 of my testimony, and it's in the confidential section so I could -- or maybe we could go into confidential mode and I could talk about it.

ALJ ROWE: Yes. Okay. We'll go back into executive session. The Commission shall now meet in executive session to consider information or records that are exempt by law from public inspection under ORS 192.660(2)(f). Representatives from the news media and those who have signed the protective order may be permitted to attend the executive session. All other members of the audience are asked to leave the room. We will also be disconnecting the phone lines. Representatives of the news media are specifically directed not to report on any of the discussions of exempt records during the executive session. Thanks.

(Whereupon, Executive Session begins.)

THE WITNESS: Okay. So, you know, really when I was looking at this, I was looking more at the greater-than-seven-day transactions. I'll just call them monthly transactions because that's mostly what they are. And if you look at the confidential Table 2, the -- you know, the value of those transactions -- there seems to have been a pretty stark shift going from 2014 to 2015, when the Company entered into the EIM. And so -- so my argument was that as a result -- that, you know, holistically, including both the, you know, day-ahead transactions and the monthly transactions, that after the EIM there was -- there was a change.

And I think, you know, my understanding with CUB's adjustment is really limited to more just the DART adjustment or the short-term transactions. So I -- so that's how I would distinguish the two adjustments, and I recognize the Commission addressed a similar issue in its order so I don't think we need to belabor that point, but, you know, the data I looked at suggested that there was a shift and that's why I made my recommendation.

BY MR. LOWNEY:

Q. Mr. Mullins, that's what I'd like to ask

you about next. I think perhaps it's best you turn to your rebuttal testimony where you have the same table that was corrected for an inadvertent error. So that would be on page 3 of ICNU/200.

A. Okay.

Q. And you testified, I believe, just a moment ago that the -- this discrete shift that you observed in the data occurs once you include those monthly transactions, correct?

A. Correct.

Q. And you would agree that if you exclude the monthly transactions and, in fact, look only at the day-ahead/real-time adjustments -- excuse me -- transactions, there's no discrete shift at all, is there?

A. Well, there's -- there's certainly a decline in the impact. So if you look at 2015 and 2016, the -- you know, the value goes down too $5.4 million -- or sorry, $15.4 for the less-than-seven-day transactions, which is, you know, a lot less than, you know, the long-term average. And probably the real -- you know, kind of real issue that I've kind of seen, is I've looked at the shorter-term transactions is, you know, 2014 just seems to be, you know -- I mean, we may have not discussed this for a long time, but 2014 seems to be kind of weird year because there was some pretty strange weather impacts in that year.

And so you see that's actually the largest value, 40.9 million and then it declines to about 30 million. And then in 2016, the less-than-seven-day transactions is about, you know. 15.4 million. And so there may be a shift there, but, you know, you really see it in the greater-than-seven-day transactions, the monthly transactions, where it goes from being an $11 million cost to being a $24.8 million benefit in 2015, and an $18.9 million benefit in 2016. And so that's the -- you know, the data that I looked at when I recommended to limit to the post-EIM period.

Q. Okay. Mr. Mullins, my question was just about the day-ahead/real-time. And you would agree, based on the information you presented in this table that the post-EIM day-ahead/real-time transactions that resulted in a systematic cost of $23.3 million as compared to $24.9 million for the entire historical period, correct? So that they were within six percent of one another, according to your own analysis, correct?

A. Well, so I didn't quite follow that. So the -- there seems to be some sort of shift after beginning with pre -- around the less-than-seven-day transactions. You know, they extent of that, I think, might be subject to debate and interpretation --

Q. I'm just asking you about the numbers. Would you agree the average systematic cost post-EIM is $23.3 million dollars? That's the number you've got in your table, correct?

A. Correct.

Q. And would you also agree that that is the mean value or, excuse me, the median value for the entire historical data set? Meaning there's as many years with DART -- systematic DART costs higher than that as there are less than that?

A. So, no. Oh, I see. So you're saying the median not the --

Q. I'm saying the median.

A. Right. Yeah, it might fall within that range. I'd have to count them up here.

Q. You can accept it subject to check if you'd like?

A. Right. So -- you know -- you know, so there's a wide range of numbers here, right. So there are three numbers below that number and there are three numbers above that number. The lowest number being 10 million and the highest being 40 million -- 40.9 million and so, yes, it would be the -- it would -- it would not be the -- necessarily the median value but it would -- it would, you know, fall within that -- that range.

Q. All right. If you could turn to page 10 of your rebuttal testimony. That's ICNU/200.

A. Okay.

Q. And if you look down at lines 13 to 17, you testified that even if the day-ahead/real-time adjustment is not limited to only 2015 and '16, included hedging benefits, still result in benefit in DART adjustment; is that correct?

A. No.

Q. Well, you say notwithstanding, even if the adjustment was not calculated over that period, including the greater-than-seven-day transactions still result in benefit in DART adjustment.

A. Yeah.

Q. Is that right?

A. That's what I'm saying. You -- yeah, so the distinction there is you said "hedging benefit," and that's not what my testimony says.

Q. Well, to be clear, if those greater-than-

seven-day transactions are included, and you look at the entire 60-month historical period, the day-ahead/real-time adjustment decreases by $1.4 million, correct?

A. Let's see, so over the entire period?

Q. Over the entire 60-month period that's used to calculate the day-ahead/real-time adjustment in this case.

A. Yeah. So --

Q. In other words --

A. Yeah. So if you refer -- I mean, those numbers are all in table -- Confidential Table 1R, and so, you know, there are a range of values, correct. So between 2011 and 2016, if you were to calculate it that way, the cost would go from 24.9 to 19.5 million. Over the Company's proposed period of measurement, it would go from 27.7 million to 26.3 million, and I believe that's the difference that you're quoting. And then if you carry it on to the post-EIM period, it goes from 23.3 million to only 1.4 million.

Q. Now, Mr. Mullins, you agree that when you refer to greater-than-seven-day transactions, you're primarily referring to monthly transactions, correct?

A. I believe they are primarily monthly transactions, correct.

Q. And a moment ago you testified that did -- that those monthly transactions are not hedging transactions, correct?

A. So those monthly transactions have a fixed price and so they have a hedging component. However, they still serve an important role in the Company's balancing activity. So, you know, if you imagine balancing, you know, over -- you know, it's kind of sort of a long-term process that the Company goes through where, you know, it's continually forecasting its loads out many years and as it's getting closer to the period when power is delivered, it's purchasing and sending power in monthly blocks to try to meet its -- to try to match its load obligations.

And so the transactions in question are not just hedging transactions. They're not just financial, you know, swap transactions. They're -- they're balancing transactions which have a fixed price, and because of that fixed price, they are -- they are -- they have the hedging component to them. And so I think it's -- it's not accurate just to, you know, wholesale characterize them as hedging transactions. And, in fact, the company in -- when it calculates the volume part of it, it's day-ahead and real-time transaction adjustment, it includes monthly transactions as system balancing transactions.

So all those additional volumes are the monthly transactions. And they're not -- you know, they're not considered hedges for that purpose. But what the Company doesn't do is it doesn't quantify the historical costs or benefit associated with those monthly transactions. So that was the goal of my analysis is to figure out whether that's a cost or benefit and how it impacts things.

Q. Now, Mr. Mullins, you would agree that the greater-than-seven-day transactions, these monthly transactions, should be included only if they produce systematic benefits, correct?

A. Could you refer to my testimony?

Q. Yes. I can point you to several places where you make that statement. So let's begin ICNU/100, page 10.

A. Okay.

Q. Beginning on line 16, you testified that in the DART adjustment, the Company adds an additional systematic cost for transactions of less

than seven days, yet does not consider whether they longer-term transactions are systematically settling favorably or unfavorably relative to market.

A. Okay.

Q. All right. So would you agree that there needs to be systematic cost or benefit in order to include those greater-than-seven-day transactions in the day-ahead/real-time adjustment?

A. Not necessarily. And that's not what this -- this piece of testimony here is saying. It just says that they look at -- that the Company is looking at one side of the equation and not the other.

Q. Well, if you could turn to your rebuttal testimony, ICNU/200, page 9. And on line 12, you testify that if there's an offsetting systematic benefit associated with these longer-term contracts, those benefits are appropriately applied against the impact of the DART. So again, you use the term "systematic," correct?

A. Correct.

Q. And your testimony is that since 2015, PacifiCorp's now systematically benefited from these monthly transactions?

A. Correct.

Q. Now, haven't you previously testified that these monthly transactions do not, in fact, increase the systematic cost or benefit?

A. I don't think so. I don't know.

Q. Well, in Docket UE 296, you provided testimony on behalf of ICNU, correct?

A. Correct.

Q. And in that case, you objected to the day-ahead/real-time adjustment, correct?

A. I did.

Q. And you claim that in that case that the adjustment improperly applied a systematic cost to monthly transactions, correct?

A. Correct.

Q. And so now you're testifying the opposite, correct?

A. Not necessarily. So the -- and maybe I could clarify that statement. So I wasn't wholesale saying that -- I'd have to go back -- so the -- I wasn't saying in that testimony that -- that the -- I was saying that there is an assumption in the GRID model in the Company's power cost forecasting. That there is no systematic costs or benefit relative to forward prices. So that was -- that was the extent of my testimony in that matter. And I've -- you know, as I've kind of considered it over the years that we've been, you know, reviewing it, you know, I've kind of delved into that concept.

So the question is whether, you know, a monthly -- or whether, you know, these four prices that are used to establish power costs are an unbiased expectation of what is going to happen in -- in the test period. And I've -- in the PGE case, I did a lot of analysis and I concluded that, well, really these four price curves are probably not an unbiased forecast, and that there are sort of risk premiums and things built into those.

And so that actually led me to sort of the investigation in -- in this matter to figure out whether there was systematic costs or benefit in connection with these monthly transactions. And, you know, that was the extent of my testimony in this matter and I found that there has been, and particularly since that -- since EIM, the systematic benefit has been quite large.

Q. Mr. Mullins, if you could turn PacifiCorp Cross-examination Exhibit 1110.

A. Okay.

MR. COWELL: Your Honor, this was the exhibit that ICNU does have an objection to if you'd like me to raise that now.

ALJ ROWE: This -- okay. Let me see where we are. 1110.

MR. LOWNEY: Your Honor, for the record, this is ICNU's brief from Docket UE 296.

ALJ ROWE: Okay. So this is the redacted version of a brief from two years ago. What was that objection?

MR. COWELL: Your Honor, the objection is that the Company's already filed an exhibit of Mr. Mullins' testimony at 1111. So anything that the Company would want to ask Mr. Mullins about his testimony could be asked in relation to that UE 296 testimony that he sponsored. And anything beyond that would just be legal briefing and statements of counsel. And earlier in this proceeding, Your Honor, I was asking questions directly of Mr. Wilding and his testimony, and the objection of the Company were sustained to have me stop in that line of questioning on the argument that Ms. Brown was available for other questions.

So here we have an even wider gap where Mr. Mullins would be asked about statements made by counsel, when all of his statements are readily available in Exhibit 1111.

ALJ ROWE: That's pretty persuasive, Mr. Lowney.

MR. LOWNEY: Well, Your Honor, I would like to have an opportunity to lay a foundation for the admission of this exhibit. This -- the analysis that's included here cites directly to Mr. Mullins' testimony. I would find it hard to believe that Mr. Mullins didn't review this beforehand.

ALJ ROWE: Can you not just work from the testimony and make the same argument?

MR. LOWNEY: I can. Frankly, there's more direct quotes that are included in the brief that will make it just a little bit quicker. And I can certainly just ask him --

ALJ ROWE: This is a tough one because it's just a brief on the one hand --

MR. LOWNEY: Your Honor, I'd be happy to simply ask him what he says in the brief, and if he can say it was all of two years ago if he would like to.

MR. COWELL: Your Honor, already on the record for Mr. Lowney is a statement about the level of Mr. Mullins' review of the briefing. Quite frankly, that was two years ago and I don't know that I could attest to it if I wanted to. So we've already got -- we'd be proceeding with an assumption of Mr. Mullins' familiarity with review that we can't verify and it would be improper.

MR. LOWNEY: Your Honor, I'd be happy to just ask questions without admitting his brief into the record, and if Mr. Mullins would like to refute his arguments from two years ago, he can do that, if they're wrong.

ALJ ROWE: Let's try that. I am agreeing with Mr. Cowell that the brief is legal and the important information should be in the testimony. So try moving through that.

MS. MCDOWELL: Okay.

BY MR. LOWNEY:

Q. Mr. Mullins, if you could turn to your testimony that's PAC/1111.

A. Okay.

Q. And on page 5 of that testimony -- so I should say it's page 5 of the exhibit, page 8 of your original testimony. Are you there?

A. **(Nods head affirmatively.)**

Q. At the very top of the beginning of line 1, you testified that if the Commission were to conclude in this proceeding that there are, in fact, systematic costs or bias associated with entering

into forward-hedging transactions, there would be a reason to rethink the prudence of the Company's entire hedging policy as well as the equity of passing those hedging costs on to customers. Do you see that testimony?

A. I do.

Q. Now, in this case, you're taking the position that there are, in fact, systematic costs biases and those costs -- excuse me, cost or benefits, and that those benefits should be passed through, through a normalized NPC forecast, correct?

A. Correct.

Q. So you're taking the opposite position?

A. No.

Q. Okay.

A. I will explain. So -- you know, so in this -- so maybe a couple points of clarification. So in this piece of testimony, I was working from the assumption that the volume portion of the Company's adjustment included costs associated with these monthly transactions. And so the -- you know, the company develops this amount of volumes and they're offsetting sales and volumes on -- on -- sales and purchase volumes on both sides, and then it assigns a cost to those, those purchases and sales.

So I was working under the assumption that that was incorporating an analysis of the historical costs and benefits of those monthly transactions, which are layered in over time. Well, that's not actually what the Company did. So the costs that's assigned to those additional volumes is just a plug to tie the impact of the DART adjustment to the historical averages. And so, you know, as I've sort of come to further understand the Company's adjustment, the volume piece is really superfluous. It's kind of a cosmetic part of the adjustment. It really doesn't matter. So really they're just tying everything back to the historical averages.

And so, you know, this whole discussion here was based off that incorrect assumption, and I will admit it's an incorrect assumption. But I think the statement is still true. It's something that, you know, particularly in light of, you know, the work that we did in PGE's gas hedging proceeding last year, that, you know, if we're concluding that there are, you know, systematic costs associated with hedging and, you know, hedging is something that's reducing the primarily Company's risk, then we ought to really think about the prudence of -- of hedging and those costs. And so I think that's something for kind of the future proceeding, but, you know, the statement here that Mr. Lowney quoted, I think still holds.

Q. All right. If you could turn to page 8 of your -- of that same exhibit, please. And on line -- again, on line 8, you testified in UE 296 that to the extent that risk-free opportunity for profit were to exist in a forward market, the mechanics of supply and demand would result in an adjustment to prices to eliminated the opportunity for a risk-free return. Do you see that?

A. Yeah.

Q. Now, your position in this case is that the Company is now systematically generating these very same risk-free returns through its monthly transactions, correct?

A. Correct. And so, you know, that again, gets back to sort of the analysis that we've done in gas hedging -- PGE's gas hedging proceeding that, you know, this probably doesn't hold in -- in electricity markets. There probably are risk premiums built into forward prices, and because of that, there are new additional costs associated with -- with these fixed-price contracts.

Now, on the power side, it's usually not as big of a deal because the purchases aren't made that -- as far in advance. But on the gas side, it becomes a bigger -- a bigger issue and I think something to look at in the future.

Q. And just to be clear, we're not talking about gas hedging policies in this case, correct?

A. No.

Q. Okay. Now, going back to what you just testified to, the presence of a risk premium and forward contract, would you agree that if there is risk premium in a forward price, that means there's going to be systematic loss on that contract, not a systematic gain?

A. Right. So, you know, it would depend on whether it's a purchase or a sale. So if you purchase power, you know, forward, then you're locking a fixed price. You're paying systematically more than what it's -- what the power will sell at. If you're -- if you're selling, it's the exact opposite, so you're getting that risk premium. But, you know, to sort of clarify, you know, my -- my adjustment for the monthly transactions, it's -- you know, it would encompass more things than just that sort of risk premium component. Because, you know, the Company is sort of layering in these transactions over time, and the thought is that over time, they are entering into these transactions, that they're, you know, sort of locking in benefits as they sort move along. So there's more to it than just -- than just hedging.

Q. Just a few more questions, Mr. Mullins. If you could turn to your rebuttal testimony, please, ICNU/200, page 5.

A. Okay.

Q. And at the top again, line 1, you testified prior to this proceeding, I had not conducted any analysis considering the greater-than-seven-day transactions within the DART framework. Do you see that?

A. I do.

Q. Now, I think today we've established pretty squarely that you, in fact, conducted extensive analysis in UE 296 involving the very same transactions in the framework of DART adjustment, correct?

A. Well, so, no. I mean, I hadn't -- I hadn't done this analysis that I prepared in my testimony in this matter. The testimony in UE 296 was largely theoretical not -- it wasn't based on an empirical study of, you know, the cost and benefits of these particular transactions.

Q. Well, just to be clear, in your testimony you said you had not conducted any analysis. And now you're saying you have conducted the same analysis; is that fair?

A. Right. So -- so I had conducted a theoretical analysis, but not an empirical analysis. And so maybe that would be a point of clarification. But as we discussed earlier, you know, as a result of this analysis, I've kind of reached a different conclusion. And -- so, yeah.

Q. Now, Mr. Mullins you testified in opposition to the day-ahead/real-time adjustment in other jurisdictions, correct?

A. I believe in Wyoming I did.

Q. And isn't it true that the Wyoming Commission, like the Oregon Commission rejected your recommendation and approved the adjustment?

A. Well, so, you know, it's -- you know, these -- they -- they did not approve my adjustment. But the-- you know, the way these things kind of get approved are kind of more complicated than that. So, you know, the -- ultimately the Commission went with, like, an entirely different test period in that matter. They went with, like, a 2015 test period from a 2016 test period so there were a lot of, you know, offsetting adjustments that went into the requirements in that matter. But they did not accept my -- my proposals related to the DART adjustment, which were largely similar to the, you know, recommendations that I made in UE 296.

MR. LOWNEY: Thank you. I have no further questions. And I don't know if we want to handle cross-examination exhibits before we do redirect or wait until after. I just want to -- to flag that.

ALJ ROWE: Let's come back to that and see if there's any -- well, normally I would go to Staff now, then redirect, then back through recross. Does that work for everyone?

MS. MOSER: It works for me.

MR. COWELL: Yes. Your Honor.

ALJ ROWE: Okay. Staff.

MS. MOSER: Okay.

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(Whereupon, Public Session resumes.)

CROSS-EXAMINATION

BY MS. MOSER:

Q. Good afternoon, Mr. Mullins.

A. Good afternoon.

Q. Can you please turn to -- do you have -- do you have PacifiCorp's testimony in front of you?

A. I do.

Q. Okay. Can you please turn to Exhibit 800, Mr. Wilding's testimony?

A. Okay.

Q. It's page 33. And I think it's line 11. I just put away my revised copy.

A. Okay.

Q. Mr. Wilding here testifies that indeed both Staff and ICNU already disagree on how to conduct backcast in the time period to cover demonstrating that the process will not be a straightforward mechanical exercise of inputting agreed upon historical data into the model, and then analyzing the output; is that correct?

A. It is correct that he says that.

Q. Okay.

A. But I -- but I wouldn't -- I wouldn't agree with the extent of what he's saying.

MS. MOSER: Are we still in executive session?

ALJ ROWE: That's what I'm asking --

MS. MOSER: Okay.

ALJ ROWE: Should we go back in public --

MS. MOSER: I have into confidential questions.

ALJ ROWE: Okay. We will go back into our normal public session, and flip back as needed. So public session.

MS. MOSER: Okay.

ALJ ROWE: Oh, and if the record could please start the public session at the beginning of Ms. Moser's questioning. All right. Thanks.

BY MS. MOSER:

Q. And ICNU in this proceeding is requesting a backcast be done; is that correct?

A. Correct.

Q. And so is Staff?

A. Correct.

Q. And in your testimony, you noted some differences between sort of what you would do ideally and from what Staff had recommended; is that correct?

A. Correct.

Q. Okay. Would you consider any difference in opinion that you might have with Staff's proposed backcast to be reason that the Company should not do a backcast?

A. No. I think that ICNU and Staff are pretty much on the -- on the same page with respect to a backcast. I think it's just making sure that we, you know, under -- you know, understand what inputs are being changed so we can, you know, determine what, you know, things that we're going to isolate in backcast. But I think there's more agreement than the Company suggests here.

Q. So would it be fair to say that you're confident that Staff and ICNU could come to an agreement on a backcast the Company could then conduct?

A. Yes.

MS. MOSER: I have no further questions.

ALJ ROWE: Is there redirect?

MR. COWELL: No redirect, Your Honor.

ALJ ROWE: Is there anything else from the bench and no cross --

MR. LOWNEY: No recross -- nothing from me other than I just wanted to clarify on the cross-examination exhibits.

ALJ ROWE: Yes, let's do those.

MR. LOWNEY: I'd really like to move into the record PAC/1108 and 1111. And 1110 was the brief, and 1109 we don't need to use -- we don't need to offer.

ALJ ROWE: Okay. You want to move into the record 1108 and what was the other one?

MR. LOWNEY: 1111.

ALJ ROWE: 1111. And that's it?

MR. LOWNEY: That's -- yeah, for -- for Mr. Mullins, yes.

ALJ ROWE: Okay. That's the -- okay. Any objections.

MR. COWELL: No objections to those two, Your Honor.

ALJ ROWE: Okay. They are moved into the record. Thank you.

(Whereupon, PAC Cross-Examination Exhibit 1108 and 1111 were moved into the record.)

ALJ ROWE: So let's see, next we have Mr. Kaufman and Mr. Gibbens. I would really like a five-minute break before Mr. Kaufman. Is that okay with everyone? Or, like, just a couple minutes.

(Whereupon, recess taken.)

ALJ ROWE: Okay. We'll go back on the

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UE 420

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PAC/1308

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September 1, 2023

Economic News Release

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CONSUMER PRICE INDEX - APRIL 2023

The Consumer Price Index for All Urban Consumers (CPI-U) rose 0.4 percent in April on a seasonally adjusted basis, after increasing 0.1 percent in March, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index increased 4.9 percent before seasonal adjustment.

The index for shelter was the largest contributor to the monthly all items increase, followed by increases in the index for used cars and trucks and the index for gasoline. The increase in the gasoline index more than offset declines in other energy component indexes, and the energy index rose 0.6 percent in April. The food index was unchanged in April, as it was in March. The index for food at home fell 0.2 percent over the month while the index for food away from home rose 0.4 percent.

The index for all items less food and energy rose 0.4 percent in April, as it did in March. Indexes which increased in April include shelter, used cars and trucks, motor vehicle insurance, recreation, household furnishings and operations, and personal care. The index for airline fares and the index for new vehicles were among those that decreased over the month.

The all items index increased 4.9 percent for the 12 months ending April; this was the smallest 12-month increase since the period ending April 2021. The all items less food and energy index rose 5.5 percent over the last 12 months. The energy index decreased 5.1 percent for the 12 months ending April, and the food index increased 7.7 percent over the last year.

Table A. Percent changes in CPI for All Urban Consumers (CPI-U): U.S. city average

	Seasonally adjusted changes from preceding month							Un-adjusted 12-mos. ended Apr. 2023
	Oct. 2022	Nov. 2022	Dec. 2022	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	
All items	0.5	0.2	0.1	0.5	0.4	0.1	0.4	4.9
Food	0.7	0.6	0.4	0.5	0.4	0.0	0.0	7.7
Food at home	0.5	0.6	0.5	0.4	0.3	-0.3	-0.2	7.1
Food away from home(1)	0.9	0.5	0.4	0.6	0.6	0.6	0.4	8.6
Energy	1.7	-1.4	-3.1	2.0	-0.6	-3.5	0.6	-5.1
Energy commodities	3.7	-2.1	-7.2	1.9	0.5	-4.6	2.7	-12.6
Gasoline (all types)	3.4	-2.3	-7.0	2.4	1.0	-4.6	3.0	-12.2
Fuel oil(1)	19.8	1.7	-16.6	-1.2	-7.9	-4.0	-4.5	-20.2
Energy services	-0.7	-0.6	1.9	2.1	-1.7	-2.3	-1.7	5.9
Electricity	0.5	0.5	1.3	0.5	0.5	-0.7	-0.7	8.4
Utility (piped) gas service	-3.7	-3.4	3.5	6.7	-8.0	-7.1	-4.9	-2.1
All items less food and energy	0.3	0.3	0.4	0.4	0.5	0.4	0.4	5.5
Commodities less food and energy commodities	-0.1	-0.2	-0.1	0.1	0.0	0.2	0.6	2.0
New vehicles	0.6	0.5	0.6	0.2	0.2	0.4	-0.2	5.4
Used cars and trucks	-1.7	-2.0	-2.0	-1.9	-2.8	-0.9	4.4	-6.6
Apparel	-0.2	0.1	0.2	0.8	0.8	0.3	0.3	3.6
Medical care commodities(1)	0.0	0.2	0.1	1.1	0.1	0.6	0.5	4.0
Services less energy services	0.5	0.5	0.6	0.5	0.6	0.4	0.4	6.8
Shelter	0.7	0.6	0.8	0.7	0.8	0.6	0.4	8.1
Transportation services	0.6	0.3	0.6	0.9	1.1	1.4	-0.2	11.0
Medical care services	-0.4	-0.5	0.3	-0.7	-0.7	-0.5	-0.1	0.4

Footnotes
(1) Not seasonally adjusted.

Food

The food index was unchanged in April. The food at home index fell 0.2 percent over the month, following a 0.3-percent decrease in March. Four of the six major grocery store food group indexes decreased over the month

Economic News Release

Consumer Price Index News Release

Transmission of material in this release is embargoed until
8:30 a.m. (ET) Wednesday, July 12, 2023 USDL-23-1523

Technical information: (202) 691-7000 * cpi_info@bls.gov * www.bls.gov/cpi
Media contact: (202) 691-5902 * PressOffice@bls.gov

CONSUMER PRICE INDEX - JUNE 2023

The Consumer Price Index for All Urban Consumers (CPI-U) rose 0.2 percent in June on a seasonally adjusted basis, after increasing 0.1 percent in May, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index increased 3.0 percent before seasonal adjustment.

The index for shelter was the largest contributor to the monthly all items increase, accounting for over 70 percent of the increase, with the index for motor vehicle insurance also contributing. The food index increased 0.1 percent in June after increasing 0.2 percent the previous month. The index for food at home was unchanged over the month while the index for food away from home rose 0.4 percent in June. The energy index rose 0.6 percent in June as the major energy component indexes were mixed.

The index for all items less food and energy rose 0.2 percent in June, the smallest 1-month increase in that index since August 2021. Indexes which increased in June include shelter, motor vehicle insurance, apparel, recreation, and personal care. The indexes for airline fares, communication, used cars and trucks, and household furnishings and operations were among those that decreased over the month.

The all items index increased 3.0 percent for the 12 months ending June; this was the smallest 12-month increase since the period ending March 2021. The all items less food and energy index rose 4.8 percent over the last 12 months. The energy index decreased 16.7 percent for the 12 months ending June, and the food index increased 5.7 percent over the last year.

Table A. Percent changes in CPI for All Urban Consumers (CPI-U): U.S. city average

	Seasonally adjusted changes from preceding month							Un-adjusted 12-mos. ended Jun. 2023
	Dec. 2022	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	May 2023	Jun. 2023	
All items	0.1	0.5	0.4	0.1	0.4	0.1	0.2	3.0
Food	0.4	0.5	0.4	0.0	0.0	0.2	0.1	5.7
Food at home	0.5	0.4	0.3	-0.3	-0.2	0.1	0.0	4.7
Food away from home(1)	0.4	0.6	0.6	0.6	0.4	0.5	0.4	7.7
Energy	-3.1	2.0	-0.6	-3.5	0.6	-3.6	0.6	-16.7
Energy commodities	-7.2	1.9	0.5	-4.6	2.7	-5.6	0.8	-26.8
Gasoline (all types)	-7.0	2.4	1.0	-4.6	3.0	-5.6	1.0	-26.5
Fuel oil(1)	-16.6	-1.2	-7.9	-4.0	-4.5	-7.7	-0.4	-36.6
Energy services	1.9	2.1	-1.7	-2.3	-1.7	-1.4	0.4	-0.9
Electricity	1.3	0.5	0.5	-0.7	-0.7	-1.0	0.9	5.4
Utility (piped) gas service	3.5	6.7	-8.0	-7.1	-4.9	-2.6	-1.7	-18.6
All items less food and energy	0.4	0.4	0.5	0.4	0.4	0.4	0.2	4.8
Commodities less food and energy commodities	-0.1	0.1	0.0	0.2	0.6	0.6	-0.1	1.3
New vehicles	0.6	0.2	0.2	0.4	-0.2	-0.1	0.0	4.1
Used cars and trucks	-2.0	-1.9	-2.8	-0.9	4.4	4.4	-0.5	-5.2
Apparel	0.2	0.8	0.8	0.3	0.3	0.3	0.3	3.1
Medical care commodities(1)	0.1	1.1	0.1	0.6	0.5	0.6	0.2	4.2
Services less energy services	0.6	0.5	0.6	0.4	0.4	0.4	0.3	6.2
Shelter	0.8	0.7	0.8	0.6	0.4	0.6	0.4	7.8
Transportation services	0.6	0.9	1.1	1.4	-0.2	0.8	0.1	8.2
Medical care services	0.3	-0.7	-0.7	-0.5	-0.1	-0.1	0.0	-0.8

Footnotes
(1) Not seasonally adjusted.

Economic News Release

Consumer Price Index News Release

Transmission of material in this release is embargoed until
8:30 a.m. (ET) Thursday, August 10, 2023 USDL-23-1734

Technical information: (202) 691-7000 * cpi_info@bls.gov * www.bls.gov/cpi
Media contact: (202) 691-5902 * PressOffice@bls.gov

CONSUMER PRICE INDEX - JULY 2023

The Consumer Price Index for All Urban Consumers (CPI-U) rose 0.2 percent in July on a seasonally adjusted basis, the same increase as in June, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index increased 3.2 percent before seasonal adjustment.

The index for shelter was by far the largest contributor to the monthly all items increase, accounting for over 90 percent of the increase, with the index for motor vehicle insurance also contributing. The food index increased 0.2 percent in July after increasing 0.1 percent the previous month. The index for food at home increased 0.3 percent over the month while the index for food away from home rose 0.2 percent in July. The energy index rose 0.1 percent in July as the major energy component indexes were mixed.

The index for all items less food and energy rose 0.2 percent in July, as it did in June. Indexes which increased in June include shelter, motor vehicle insurance, education, and recreation. The indexes for airline fares, used cars and trucks, medical care, and communication were among those that decreased over the month.

The all items index increased 3.2 percent for the 12 months ending July, slightly more than the 3.0-percent increase for the 12 months ending in June. The all items less food and energy index rose 4.7 percent over the last 12 months. The energy index decreased 12.5 percent for the 12 months ending July, and the food index increased 4.9 percent over the last year.

Table A. Percent changes in CPI for All Urban Consumers (CPI-U): U.S. city average

	Seasonally adjusted changes from preceding month							Un-adjusted 12-mos. ended Jul. 2023
	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	May 2023	Jun. 2023	Jul. 2023	
All items	0.5	0.4	0.1	0.4	0.1	0.2	0.2	3.2
Food	0.5	0.4	0.0	0.0	0.2	0.1	0.2	4.9
Food at home	0.4	0.3	-0.3	-0.2	0.1	0.0	0.3	3.6
Food away from home(1)	0.6	0.6	0.6	0.4	0.5	0.4	0.2	7.1
Energy	2.0	-0.6	-3.5	0.6	-3.6	0.6	0.1	-12.5
Energy commodities	1.9	0.5	-4.6	2.7	-5.6	0.8	0.3	-20.3
Gasoline (all types)	2.4	1.0	-4.6	3.0	-5.6	1.0	0.2	-19.9
Fuel oil(1)	-1.2	-7.9	-4.0	-4.5	-7.7	-0.4	3.0	-26.5
Energy services	2.1	-1.7	-2.3	-1.7	-1.4	0.4	-0.1	-1.1
Electricity	0.5	0.5	-0.7	-0.7	-1.0	0.9	-0.7	3.0
Utility (piped) gas service	6.7	-8.0	-7.1	-4.9	-2.6	-1.7	2.0	-13.7
All items less food and energy	0.4	0.5	0.4	0.4	0.4	0.2	0.2	4.7
Commodities less food and energy commodities	0.1	0.0	0.2	0.6	0.6	-0.1	-0.3	0.8
New vehicles	0.2	0.2	0.4	-0.2	-0.1	0.0	-0.1	3.5
Used cars and trucks	-1.9	-2.8	-0.9	4.4	4.4	-0.5	-1.3	-5.6
Apparel	0.8	0.8	0.3	0.3	0.3	0.3	0.0	3.2
Medical care commodities(1)	1.1	0.1	0.6	0.5	0.6	0.2	0.5	4.1
Services less energy services	0.5	0.6	0.4	0.4	0.4	0.3	0.4	6.1
Shelter	0.7	0.8	0.6	0.4	0.6	0.4	0.4	7.7
Transportation services	0.9	1.1	1.4	-0.2	0.8	0.1	0.3	9.0
Medical care services	-0.7	-0.7	-0.5	-0.1	-0.1	0.0	-0.4	-1.5

Footnotes
(1) Not seasonally adjusted.

Food

PUBLIC UTILITY COMMISSION
OF OREGON

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PAC/1309

Federal Open Market Committee Projections June 14, 2023

September 1, 2023

Federal Open Market Committee

June 14, 2023: FOMC Projections materials, accessible version

Accessible version

For release at 2:00 p.m., EDT, June 14, 2023

Summary of Economic Projections

In conjunction with the Federal Open Market Committee (FOMC) meeting held on June 13–14, 2023, meeting participants submitted their projections of the most likely outcomes for real gross domestic product (GDP) growth, the unemployment rate, and inflation for each year from 2023 to 2025 and over the longer run. Each participant's projections were based on information available at the time of the meeting, together with her or his assessment of appropriate monetary policy—including a path for the federal funds rate and its longer-run value—and assumptions about other factors likely to affect economic outcomes. The longer-run projections represent each participant's assessment of the value to which each variable would be expected to converge, over time, under appropriate monetary policy and in the absence of further shocks to the economy. "Appropriate monetary policy" is defined as the future path of policy that each participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her individual interpretation of the statutory mandate to promote maximum employment and price stability.

Table 1. Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents, under their individual assumptions of projected appropriate monetary policy, June 2023

Percent

Variable	Median				Central Tendency				Ra	
	2023	2024	2025	Longer run	2023	2024	2025	Longer run	2023	2024
Change in real GDP	1.0	1.1	1.8	1.8	0.7–1.2	0.9–1.5	1.6–2.0	1.7–2.0	0.5–2.0	0.5–2.2
March projection	0.4	1.2	1.9	1.8	0.0–0.8	1.0–1.5	1.7–2.1	1.7–2.0	-0.2–1.3	0.3–2.0
Unemployment rate	4.1	4.5	4.5	4.0	4.0–4.3	4.3–4.6	4.3–4.6	3.8–4.3	3.9–4.5	4.0–5.0
March projection	4.5	4.6	4.6	4.0	4.0–4.7	4.3–4.9	4.3–4.8	3.8–4.3	3.9–4.8	4.0–5.2
PCE inflation	3.2	2.5	2.1	2.0	3.0–3.5	2.3–2.8	2.0–2.4	2.0	2.9–4.1	2.1–3.5
March projection	3.3	2.5	2.1	2.0	3.0–3.8	2.2–2.8	2.0–2.2	2.0	2.8–4.1	2.0–3.5
Core PCE	3.9	2.6	2.2		3.7–4.2	2.5–3.1	2.0–2.4		3.6–4.5	2.2–3.6

Variable	Median				Central Tendency				Ra
	2023	2024	2025	Longer run	2023	2024	2025	Longer run	2023	2024
inflation[4]										
March projection	3.6	2.6	2.1		3.5–3.9	2.3–2.8	2.0–2.2		3.5–4.1	2.1–3.1
Memo: Projected appropriate policy path										
Federal funds rate	5.6	4.6	3.4	2.5	5.4–5.6	4.4–5.1	2.9–4.1	2.5–2.8	5.1–6.1	3.6–5.9
March projection	5.1	4.3	3.1	2.5	5.1–5.6	3.9–5.1	2.9–3.9	2.4–2.6	4.9–5.9	3.4–5.6

Note: Projections of change in real gross domestic product (GDP) and projections for both measures of inflation are percent changes from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The projections for the federal funds rate are the value of the midpoint of the projected appropriate target range for the federal funds rate or the projected appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. The March projections were made in conjunction with the meeting of the Federal Open Market Committee on March 21–22, 2023. One participant did not submit longer-run projections for the change in real GDP, the unemployment rate, or the federal funds rate in conjunction with the March 21–22, 2023, meeting, and one participant did not submit such projections in conjunction with the June 13–14, 2023, meeting.

1. For each period, the median is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections. Return to table

2. The central tendency excludes the three highest and three lowest projections for each variable in each year. Return to table

3. The range for a variable in a given year includes all participants' projections, from lowest to highest, for that variable in that year. Return to table

4. Longer-run projections for core PCE inflation are not collected. Return to table

Figure 1. Medians, central tendencies, and ranges of economic projections, 2023–25 and over the longer run

Change in real GDP

Percent

	2018	2019	2020	2021	2022	2023	2024	2025	Longer run
Actual	2.3	2.6	-1.5	5.7	.9	-	-	-	-
Upper End of Range	-	-	-	-	-	2.0	2.2	2.2	2.5
Upper End of Central Tendency	-	-	-	-	-	1.2	1.5	2.0	2.0
Median	-	-	-	-	-	1.0	1.1	1.8	1.8
Lower End of Central Tendency	-	-	-	-	-	.7	.9	1.6	1.7
Lower End of Range	-	-	-	-	-	.5	.5	1.5	1.6

Unemployment rate

Percent

	2018	2019	2020	2021	2022	2023	2024	2025	Longer run
Actual	3.8	3.6	6.8	4.2	3.6	-	-	-	-
Upper End of Range	-	-	-	-	-	4.5	5.0	4.9	4.4
Upper End of Central Tendency	-	-	-	-	-	4.3	4.6	4.6	4.3
Median	-	-	-	-	-	4.1	4.5	4.5	4.0
Lower End of Central Tendency	-	-	-	-	-	4.0	4.3	4.3	3.8
Lower End of Range	-	-	-	-	-	3.9	4.0	3.8	3.5

PCE inflation

Percent

	2018	2019	2020	2021	2022	2023	2024	2025	Longer run
Actual	2.0	1.5	1.2	5.7	5.7	-	-	-	-
Upper End of Range	-	-	-	-	-	4.1	3.5	3.0	2.0
Upper End of Central Tendency	-	-	-	-	-	3.5	2.8	2.4	2.0
Median	-	-	-	-	-	3.2	2.5	2.1	2.0
Lower End of Central Tendency	-	-	-	-	-	3.0	2.3	2.0	2.0
Lower End of Range	-	-	-	-	-	2.9	2.1	2.0	2.0

Core PCE inflation

Percent

	2018	2019	2020	2021	2022	2023	2024	2025
Actual	2.0	1.6	1.4	4.7	4.8	-	-	-
Upper End of Range	-	-	-	-	-	4.5	3.6	3.0
Upper End of Central Tendency	-	-	-	-	-	4.2	3.1	2.4
Median	-	-	-	-	-	3.9	2.6	2.2
Lower End of Central Tendency	-	-	-	-	-	3.7	2.5	2.0
Lower End of Range	-	-	-	-	-	3.6	2.2	2.0

Note: Definitions of variables and other explanations are in the notes to table 1. The data for the actual values of the variables are annual.

Figure 2. FOMC participants' assessments of appropriate monetary policy: Midpoint of target range or target level for the federal funds rate

Number of participants with projected midpoint of target range or target level

Midpoint of target range or target level (Percent)	2023	2024	2025	Longer run
6.250				

Midpoint of target range or target level (Percent)	2023	2024	2025	Longer run
6.125	1			
6.000				
5.875	2	1		
5.750				
5.625	9	2	1	
5.500				
5.375	4			
5.250				
5.125	2	3		
5.000				
4.875		2	1	
4.750				
4.625		2	1	
4.500				
4.375		6		
4.250				
4.125		1	2	
4.000				
3.875			1	
3.750				
3.625		1	2	1
3.500				
3.375			3	
3.250				1
3.125			3	
3.000				1
2.875			1	
2.750				2
2.625			2	2
2.500				7
2.375			1	3
2.250				

Note: Each shaded circle indicates the value (rounded to the nearest 1/8 percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. One participant did not submit longer-run projections for the federal funds rate.

Figure 3.A. Distribution of participants' projections for the change in real GDP, 2023–25 and over the longer run

Histograms, four panels.

Number of participants

Percent Range	2023		2024		2025		Longer Run	
	March projections	June projections	March projections	June projections	March projections	June projections	March projections	June projections
-0.4 - -0.3								
-0.2 - -0.1	3							
0.0 - 0.1	2							

Percent Range	2023		2024		2025		Longer Run	
	March projections	June projections	March projections	June projections	March projections	June projections	March projections	June projections
0.2 - 0.3	4		1					
0.4 - 0.5	1	1		2				
0.6 - 0.7	4	3		1				
0.8 - 0.9	1	5		2				
1.0 - 1.1	1	5	7	6				
1.2 - 1.3	2	2	3	2				
1.4 - 1.5		1	4	2	1	1		
1.6 - 1.7					5	8	6	6
1.8 - 1.9					4	4	7	7
2.0 - 2.1		1	3	2	6	4	3	3
2.2 - 2.3				1	2	1		
2.4 - 2.5							1	1

Note: Definitions of variables and other explanations are in the notes to table 1.

Figure 3.B. Distribution of participants' projections for the unemployment rate, 2023–25 and over the longer run

Histograms, four panels.

Number of participants

Percent Range	2023		2024		2025		Longer Run	
	March projections	June projections	March projections	June projections	March projections	June projections	March projections	June projections
3.2 - 3.3								
3.4 - 3.5							2	2
3.6 - 3.7								
3.8 - 3.9	2	3			1	1	3	3
4.0 - 4.1	2	9	3	3	2	2	6	5
4.2 - 4.3	1	5	1	1	3	2	5	6
4.4 - 4.5	7	1	2	7	1	7		1
4.6 - 4.7	4		7	5	6	4	1	
4.8 - 4.9	2		3	1	5	2		
5.0 - 5.1				1				
5.2 - 5.3			2					

Note: Definitions of variables and other explanations are in the notes to table 1.

Figure 3.C. Distribution of participants' projections for PCE inflation, 2023–25 and over the longer run

Histograms, four panels.

Number of participants

Percent Range	2023		2024		2025		Longer Run	
	March projections	June projections	March projections	June projections	March projections	June projections	March projections	June projections
1.7 - 1.8								
1.9 - 2.0			1		7	6	18	18
2.1 - 2.2			3	2	9	8		
2.3 - 2.4			3	6		1		
2.5 - 2.6			4	2		1		
2.7 - 2.8	1		6	5	1	1		
2.9 - 3.0	3	6			1	1		
3.1 - 3.2	5	3		2				
3.3 - 3.4	2	2						
3.5 - 3.6	3	5	1	1				
3.7 - 3.8	1	1						
3.9 - 4.0	2							
4.1 - 4.2	1	1						

Note: Definitions of variables and other explanations are in the notes to table 1.

Figure 3.D. Distribution of participants' projections for core PCE inflation, 2023–25

Histograms, three panels.

Number of participants

Percent Range	2023		2024		2025	
	March projections	June projections	March projections	June projections	March projections	June projections
1.7 - 1.8						
1.9 - 2.0					7	5
2.1 - 2.2			3	1	9	8
2.3 - 2.4			3	2		2
2.5 - 2.6			5	7		1
2.7 - 2.8			4	2	1	1
2.9 - 3.0			2	2	1	1
3.1 - 3.2			1	2		
3.3 - 3.4				1		
3.5 - 3.6	10	1		1		
3.7 - 3.8	3	7				
3.9 - 4.0	4	5				
4.1 - 4.2	1	4				
4.3 - 4.4						
4.5 - 4.6		1				

Note: Definitions of variables and other explanations are in the notes to table 1.

Figure 3.E. Distribution of participants' judgments of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate, 2023–25 and over the longer run

Histograms, four panels.

Number of participants

Percent Range	2023		2024		2025		Longer Run	
	March projections	June projections	March projections	June projections	March projections	June projections	March projections	June projections
1.88 - 2.12								
2.13 - 2.37							3	
2.38 - 2.62					1	1	10	11
2.63 - 2.87					2	2	1	3
2.88 - 3.12					4	1	1	1
3.13 - 3.37					4	3	1	1
3.38 - 3.62			1		2	3		
3.63 - 3.87			1	1	1	2	1	1
3.88 - 4.12			2		1	1		
4.13 - 4.37			5	1	1	2		
4.38 - 4.62			2	6	1			
4.63 - 4.87			3	2		1		
4.88 - 5.12	1			2		1		
5.13 - 5.37	10	2	2	3				
5.38 - 5.62	3	4	1					
5.63 - 5.87	3	9	1	2	1	1		
5.88 - 6.12	1	2		1				
6.13 - 6.37		1						

Note: Definitions of variables and other explanations are in the notes to table 1.

Figure 4.A. Uncertainty and risks in projections of GDP growth

Median projection and confidence interval based on historical forecast errors

Change in Real GDP

Percent

	2018	2019	2020	2021	2022	2023	2024	2025
Actual	2.3	2.6	-1.5	5.7	.9	-	-	-
Upper end of 70% Confidence Interval	-	-	-	-	-	2.5	3	4.1
Median	-	-	-	-	-	1.0	1.1	1.8
Lower End of 70% Confidence Interval	-	-	-	-	-	-0.5	-0.8	-0.5

FOMC participants' assessments of uncertainty and risks around their economic projections

Histograms, two panels.

Uncertainty about GDP growth

Number of participants

	Lower	Broadly Similar	Higher
June projections	0	4	14
March projections	0	0	18

Risks to GDP growth

Number of participants

	Weighted to Downside	Broadly Balanced	Weighted to Upside
June projections	10	7	1
March projections	17	1	0

Note: The blue and red lines in the top panel show actual values and median projected values, respectively, of the percent change in real gross domestic product (GDP) from the fourth quarter of the previous year to the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

Figure 4.B. Uncertainty and risks in projections of the unemployment rate

Median projection and confidence interval based on historical forecast errors

Unemployment rate

Percent

	2018	2019	2020	2021	2022	2023	2024	2025
Actual	3.8	3.6	6.8	4.2	3.6	-	-	-
Upper end of 70% Confidence Interval	-	-	-	-	-	4.9	5.9	6.4
Median	-	-	-	-	-	4.1	4.5	4.5
Lower End of 70% Confidence Interval	-	-	-	-	-	3.3	3.1	2.6

FOMC participants' assessments of uncertainty and risks around their economic projections

Histograms, two panels.

Uncertainty about the unemployment rate

Number of participants

	Lower	Broadly Similar	Higher
June projections	0	4	14
March projections	0	1	17

Risks to the unemployment rate

Number of participants

	Weighted to Downside	Broadly Balanced	Weighted to Upside
June projections	0	7	11
March projections	0	2	16

Note: The blue and red lines in the top panel show actual values and median projected values, respectively, of the average civilian unemployment rate in the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

Figure 4.C. Uncertainty and risks in projections of PCE inflation

Median projection and confidence interval based on historical forecast errors

PCE inflation

Percent

	2018	2019	2020	2021	2022	2023	2024	2025
Actual	2.0	1.5	1.2	5.7	5.7	-	-	-
Upper end of 70% Confidence Interval	-	-	-	-	-	4.2	4.2	3.5
Median	-	-	-	-	-	3.2	2.5	2.1
Lower End of 70% Confidence Interval	-	-	-	-	-	2.2	0.8	0.7

FOMC participants' assessments of uncertainty and risks around their economic projections

Histograms, four panels.

Uncertainty about PCE inflation

Number of participants

	Lower	Broadly Similar	Higher
June projections	1	1	16
March projections	0	1	17

Risks to PCE inflation

Number of participants

	Weighted to Downside	Broadly Balanced	Weighted to Upside
June projections	0	6	12
March projections	0	7	11

Uncertainty about core PCE inflation

Number of participants

	Lower	Broadly Similar	Higher
June projections	1	1	16
March projections	0	1	17

Risks to core PCE inflation

Number of participants

	Weighted to Downside	Broadly Balanced	Weighted to Upside
June projections*	0	5	13
March projections	0	7	11

Note: The blue and red lines in the top panel show actual values and median projected values, respectively, of the percent change in the price index for personal consumption expenditures (PCE) from the fourth quarter of the previous year to the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

*On July 5, 2023, the HTML version of the "Risks to core PCE inflation" histogram in Figure 4.C was corrected to accurately reflect the number of participants who indicated Broadly Balanced and Weighted to Upside in the June projections (previously reported as 6 and 12, respectively).

Figure 4.D. Diffusion indexes of participants' uncertainty assessments

Diffusion index

SEP	Change in real GDP	Unemployment rate	PCE inflation	Core PCE inflation
October 2007	0.76	0.53	0.35	0.06
January 2008	0.88	0.76	0.29	0.29
April 2008	0.82	0.71	0.59	0.41
June 2008	0.76	0.65	0.82	0.47
October 2008	1	0.94	0.65	0.71
January 2009	1	1	0.88	0.88
April 2009	1	1	0.82	0.82
June 2009	0.94	0.94	0.76	0.76

SEP	Change in real GDP	Unemployment rate	PCE inflation	Core PCE inflation
November 2009	0.94	0.82	0.76	0.82
January 2010	0.82	0.71	0.71	0.76
April 2010	0.71	0.76	0.71	0.65
June 2010	0.82	0.76	0.71	0.65
November 2010	0.89	0.83	0.72	0.72
January 2011	0.72	0.67	0.72	0.67
April 2011	0.59	0.65	0.71	0.59
June 2011	0.76	0.76	0.76	0.65
November 2011	0.94	0.82	0.65	0.59
January 2012	0.94	0.82	0.53	0.47
April 2012	0.76	0.76	0.47	0.35
June 2012	0.95	0.95	0.47	0.37
September 2012	0.89	0.89	0.37	0.32
December 2012	0.95	0.89	0.26	0.26
March 2013	0.63	0.63	0.16	0.16
June 2013	0.37	0.32	0.16	0.16
September 2013	0.24	0.24	0.12	0.12
December 2013	0.18	0.18	0	0
March 2014	0.12	0.12	0.06	0.06
June 2014	0.19	0.12	0.12	0.12
September 2014	0.24	0.24	0.06	0.06
December 2014	0.06	0.12	0.24	0.12
March 2015	0.12	0.12	0.24	0.18
June 2015	0.18	0.12	0.18	0.06
September 2015	0.12	0.06	0.18	0.18
December 2015	0.12	0.06	0.12	0.12
March 2016	0	0	0.12	0.06
June 2016	0.18	0.06	0.06	0
September 2016	0	0	0.12	-0.06
December 2016	0.35	0.29	0.24	0.18
March 2017	0.29	0.24	0.18	0.18
June 2017	0.12	0	0	0
September 2017	0.12	0	0	0
December 2017	0.12	0.12	0	0
March 2018	0.07	0.07	0	0
June 2018	0.07	0.07	0.07	0.07
September 2018	0.12	0.19	0.06	0.06
December 2018	0.18	0.29	0.06	0.06
March 2019	0.18	0.24	0.12	0.12
June 2019	0.35	0.47	0.18	0.18
September 2019	0.35	0.47	0.24	0.24
December 2019	0.24	0.24	0.12	0.12
June 2020	1	1	1	1
September 2020	1	1	0.94	0.94
December 2020	0.94	0.94	0.82	0.82
March 2021	0.83	0.89	0.89	0.89
June 2021	0.83	0.89	1	1
September 2021	0.94	0.89	1	1
December 2021	0.94	0.94	1	1
March 2022	0.94	0.88	1	1

SEP	Change in real GDP	Unemployment rate	PCE inflation	Core PCE inflation
June 2022	1	0.94	1	1
September 2022	1	1	1	1
December 2022	0.95	0.89	1	1
March 2023	1	0.94	0.94	0.94
June 2023	0.78	0.78	0.83	0.83

Note: For each SEP, participants provided responses to the question “Please indicate your judgment of the uncertainty attached to your projections relative to the levels of uncertainty over the past 20 years.” Each point in the diffusion indexes represents the number of participants who responded “Higher” minus the number who responded “Lower,” divided by the total number of participants. Figure excludes March 2020 when no projections were submitted.

Figure 4.E. Diffusion indexes of participants’ risk weightings

Diffusion index

SEP	Change in real GDP	Unemployment rate	PCE inflation	Core PCE inflation
October 2007	-0.76	0.71	0.47	0.41
January 2008	-0.71	0.76	0.35	0.29
April 2008	-0.76	0.71	0.47	0.41
June 2008	-0.82	0.82	0.76	0.53
October 2008	-0.82	0.88	-0.29	-0.18
January 2009	-0.81	0.88	-0.44	-0.44
April 2009	-0.65	0.71	-0.24	-0.24
June 2009	-0.41	0.41	-0.06	-0.06
November 2009	-0.06	0.18	0	-0.06
January 2010	-0.06	0.18	0.06	0.06
April 2010	0.18	0.06	0	0
June 2010	-0.53	0.47	-0.18	-0.18
November 2010	-0.33	0.5	-0.17	-0.17
January 2011	0.11	0.11	0.06	0.06
April 2011	-0.12	0.06	0.47	0.35
June 2011	-0.65	0.53	0.29	0.24
November 2011	-0.65	0.65	-0.06	-0.06
January 2012	-0.65	0.59	0	0
April 2012	-0.47	0.53	0.18	0.12
June 2012	-0.79	0.68	-0.16	-0.16
September 2012	-0.74	0.68	-0.05	-0.05
December 2012	-0.68	0.68	-0.05	-0.05
March 2013	-0.42	0.32	-0.11	-0.11
June 2013	-0.37	0.32	-0.16	-0.16
September 2013	-0.47	0.24	-0.24	-0.24
December 2013	-0.12	0.06	-0.18	-0.18
March 2014	-0.12	0	-0.25	-0.25
June 2014	-0.25	0.06	-0.12	-0.12
September 2014	-0.18	-0.06	-0.24	-0.24
December 2014	-0.12	-0.06	-0.29	-0.24
March 2015	-0.24	0	-0.41	-0.41
June 2015	-0.24	0.06	-0.24	-0.24
September 2015	-0.41	0.29	-0.47	-0.47
December 2015	-0.12	0	-0.41	-0.47

SEP	Change in real GDP	Unemployment rate	PCE inflation	Core PCE inflation
March 2016	-0.47	0.12	-0.65	-0.59
June 2016	-0.35	0.18	-0.35	-0.35
September 2016	-0.18	0.06	-0.24	-0.24
December 2016	0.18	-0.18	0.06	0.06
March 2017	0.18	-0.24	0.18	0.18
June 2017	0.06	-0.12	-0.06	-0.06
September 2017	0	-0.06	-0.19	-0.19
December 2017	0.19	-0.19	0	0
March 2018	0.2	-0.27	0.2	0.2
June 2018	0.07	-0.07	0.07	0.07
September 2018	0.06	-0.06	0.19	0.19
December 2018	-0.12	-0.06	0.06	0.06
March 2019	-0.24	0.06	-0.18	-0.18
June 2019	-0.82	0.71	-0.53	-0.53
September 2019	-0.76	0.53	-0.29	-0.29
December 2019	-0.53	0.47	-0.35	-0.35
June 2020	-0.71	0.71	-0.76	-0.76
September 2020	-0.65	0.65	-0.59	-0.59
December 2020	-0.29	0.41	-0.47	-0.47
March 2021	0.06	-0.06	0.22	0.22
June 2021	0.06	-0.06	0.72	0.72
September 2021	-0.22	0.06	0.72	0.72
December 2021	-0.22	0.06	0.83	0.83
March 2022	-0.56	0.5	1	1
June 2022	-0.67	0.72	0.89	0.89
September 2022	-0.89	0.95	0.89	0.89
December 2022	-0.89	0.89	0.84	0.84
March 2023	-0.94	0.89	0.61	0.61
June 2023	-0.5	0.61	0.67	0.72

Note: For each SEP, participants provided responses to the question "Please indicate your judgment of the risk weighting around your projections." Each point in the diffusion indexes represents the number of participants who responded "Weighted to the Upside" minus the number who responded "Weighted to the Downside," divided by the total number of participants. Figure excludes March 2020 when no projections were submitted.

Figure 5. Uncertainty and risks in projections of the federal funds rate

Median projection and confidence interval based on historical forecast errors

Federal Funds Rate

Percent

	2018	2019	2020	2021	2022	2023	2024	2025
Actual	2.4	1.6	.1	.1	4.4	-	-	-
Upper end of 70% Confidence Interval	-	-	-	-	-	6.3	6.5	5.6
Median	-	-	-	-	-	5.6	4.6	3.4
Lower End of 70% Confidence Interval	-	-	-	-	-	4.9	2.7	1.2

Note: The blue and red lines are based on actual values and median projected values, respectively, of the Committee's target for the federal funds rate at the end of the year indicated. The actual values are the midpoint of the target range; the median projected values are based on either the midpoint of the target range or the target level. The confidence interval around the median projected values is based on root mean squared errors of various private and government forecasts made over the previous 20 years. The confidence interval is not strictly consistent with the projections for the federal funds rate, primarily because these projections are not forecasts of the likeliest outcomes for the federal funds rate, but rather projections of participants' individual assessments of appropriate monetary policy. Still, historical forecast errors provide a broad sense of the uncertainty around the future path of the federal funds rate generated by the uncertainty about the macroeconomic variables as well as additional adjustments to monetary policy that may be appropriate to offset the effects of shocks to the economy.

The confidence interval is assumed to be symmetric except when it is truncated at zero - the bottom of the lowest target range for the federal funds rate that has been adopted in the past by the Committee. This truncation would not be intended to indicate the likelihood of the use of negative interest rates to provide additional monetary policy accommodation if doing so was judged appropriate. In such situations, the Committee could also employ other tools, including forward guidance and large-scale asset purchases, to provide additional accommodation. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections.

* The confidence interval is derived from forecasts of the average level of short-term interest rates in the fourth quarter of the year indicated; more information about these data is available in table 2. The shaded area encompasses less than a 70 percent confidence interval if the confidence interval has been truncated at zero.

Table 2. Average Historical Projection Error Ranges

Percentage points

Variable	2023	2024	2025
Change in real GDP[1]	±1.5	±1.9	±2.3
Unemployment rate[1]	±0.8	±1.4	±1.9
Total consumer prices[2]	±1.0	±1.7	±1.4
Short-term interest rates[3]	±0.7	±1.9	±2.2

Note: Error ranges shown are measured as plus or minus the root mean squared error of projections for 2003 through 2022 that were released in the summer by various private and government forecasters. As described in the box "Forecast Uncertainty," under certain assumptions, there is about a 70 percent probability that actual outcomes for real GDP, unemployment, consumer prices, and the federal funds rate will be in ranges implied by the average size of projection errors made in the past. For more information, see David Reifschneider and Peter Tulip (2017), "Gauging the Uncertainty of the Economic Outlook Using Historical Forecasting Errors: The Federal Reserve's Approach," Finance and Economics Discussion Series 2017-020 (Washington: Board of Governors of the Federal Reserve System, February), https://dx.doi.org/10.17016/FEDS.2017.020 .

1. Definitions of variables are in the general note to table 1. Return to table

2. Measure is the overall consumer price index, the price measure that has been most widely used in government and private economic forecasts. Projections are percent changes on a fourth quarter to fourth quarter basis. Return to table

3. For Federal Reserve staff forecasts, measure is the federal funds rate. For other forecasts, measure is the rate on 3-month Treasury bills. Projection errors are calculated using average levels, in percent, in the fourth quarter. Return to table

Forecast Uncertainty

The economic projections provided by the members of the Board of Governors and the presidents of the Federal Reserve Banks inform discussions of monetary policy among policymakers and can aid public understanding of the basis for policy actions. Considerable uncertainty attends these projections, however. The economic and statistical models and relationships used to help produce economic forecasts are necessarily imperfect descriptions of the real world, and the future path of the economy can be affected by myriad unforeseen developments and events. Thus, in setting the stance of monetary policy, participants consider not only what appears to be the most likely economic outcome as embodied in their projections, but also the range of alternative possibilities, the likelihood of their occurring, and the potential costs to the economy should they occur.

Table 2 summarizes the average historical accuracy of a range of forecasts, including those reported in past *Monetary Policy Reports* and those prepared by the Federal Reserve Board's staff in advance of meetings of the Federal Open Market Committee (FOMC). The projection error ranges shown in the table illustrate the considerable uncertainty associated with economic forecasts. For example, suppose a participant projects that real gross domestic product (GDP) and total consumer prices will rise steadily at annual rates of, respectively, 3 percent and 2 percent. If the uncertainty attending those projections is similar to that experienced in the past and the risks around the projections are broadly balanced, the numbers reported in table 2 would imply a probability of about 70 percent that actual GDP would expand within a range of 1.5 to 4.5 percent in the current year, 1.1 to 4.9 percent in the second year, and 0.7 to 5.3 percent in the third year. The corresponding 70 percent confidence intervals for overall inflation would be 1.0 to 3.0 percent in them current year, 0.3 to 3.7 percent in the second year, and 0.6 to 3.4 percent in the third year. Figures 4.A through 4.C illustrate these confidence bounds in "fan charts" that are symmetric and centered on the medians of FOMC participants' projections for GDP growth, the unemployment rate, and inflation. However, in some instances, the risks around the projections may not be symmetric. In particular, the unemployment rate cannot be negative; furthermore, the risks around a particular projection might be tilted to either the upside or the downside, in which case the corresponding fan chart would be asymmetrically positioned around the median projection.

Because current conditions may differ from those that prevailed, on average, over history, participants provide judgments as to whether the uncertainty attached to their projections of each economic variable is greater than, smaller than, or broadly similar to typical levels of forecast uncertainty seen in the past 20 years, as presented in table 2 and reflected in the widths of the confidence intervals shown in the top panels of figures 4.A through 4.C. Participants' current assessments of the uncertainty surrounding their projections are summarized in the bottom-left panels of those figures. Participants also provide judgments as to whether the risks to their projections are weighted to the upside, are weighted to the downside, or are broadly balanced. That is, while the symmetric historical fan charts shown in the top panels of figures 4.A through 4.C imply that the risks to participants' projections are balanced, participants may judge that there is a greater risk that a given variable will be above rather than below their projections. These judgments are summarized in the lower-right panels of figures 4.A through 4.C.

As with real activity and inflation, the outlook for the future path of the federal funds rate is subject to considerable uncertainty. This uncertainty arises primarily because each participant's assessment of the appropriate stance of monetary policy depends importantly on the evolution of real activity and inflation over time. If economic conditions evolve in an unexpected manner, then assessments of the appropriate setting of the federal funds rate would change from that point forward. The final line in table 2 shows the error ranges for forecasts of short-term interest rates. They suggest that the historical confidence intervals associated with projections of the federal funds rate are quite wide. It should be noted, however, that these confidence intervals are not strictly consistent with the projections for the federal funds rate, as these projections are not forecasts of the most likely quarterly outcomes but rather are projections of participants' individual assessments of appropriate monetary policy and are on an endof-year basis. However, the forecast errors should provide a sense of the uncertainty around the future path of the federal funds rate generated by the uncertainty about the macroeconomic variables as well as additional adjustments to monetary policy that would be appropriate to offset the effects of shocks to the economy.

If at some point in the future the confidence interval around the federal funds rate were to extend below zero, it would be truncated at zero for purposes of the fan chart shown in figure 5; zero is the bottom of the lowest target range for the federal funds rate that has been adopted by the Committee in the past. This approach to the construction of the federal funds rate fan chart would be merely a convention; it would not have any implications for possible future policy decisions regarding the use of negative interest rates to provide additional monetary policy accommodation if doing so were appropriate. In such situations, the Committee could also employ other tools, including forward guidance and asset purchases, to provide additional accommodation.

While figures 4.A through 4.C provide information on the uncertainty around the economic projections, figure 1 provides information on the range of views across FOMC participants. A comparison of figure 1 with figures 4.A through 4.C shows that the dispersion of the projections across participants is much smaller than the average forecast errors over the past 20 years.

Last Update: July 05, 2023

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1310

Docket No. UE 420
Staff Discovery Responses to PacifiCorp

REDACTED

September 1, 2023

Date: August 23, 2023

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 200
PORTLAND OR 97232
datarequest@pacificorp.com

FROM: Julie Jent
Economist
Rates, Safety and Utility Performance Program

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 – PacifiCorp Data Request filed August 17, 2023

Data Request No 07:

7. Refer to Staff/800, Jent/10, line 2. Staff recommends a $66.21 million **Oregon- allocated** adjustment to net power costs (NPC) based on the day-ahead / real-time (DA/RT) volume component. However, this number appears to be a total-company number.
    a. Please confirm that $66.21 million is a total-company number. If confirmed, please provide an Oregon-allocated amount.
    b. If not confirmed, please explain how the Oregon-allocated adjustment of $66.21 million is derived.

OPUC Response No 07:

A. Yes. However, the original $5.2 million adjustment Staff recommended is Oregon allocated, to Staff's knowledge. This number was taken from UE 400 OT from PAC which discussed the NPC impact of the change to the price adder of the DA/RT adjustment. However, the $60 million figure as a result of the July "correction" to the volume component was expressed as a system total. Staff incorrectly combined these two figures for a $66.21 million adjustment. However, after applying ~27% for OR allocated to the $60M, it should have been around ~$16.5M. So in total, if my RT adjustment would have correctly used the Oregon allocated number, my recommendation would have been ~$21.7M.

Date: August 23, 2023

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 200
PORTLAND OR 97232
datarequest@pacificorp.com

FROM: Julie Jent
Economist
Rates, Safety and Utility Performance Program

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 – PacifiCorp Data Request filed August 17, 2023

Data Request No 08:

8. Refer to Staff/800, Jent/7, lines 14 – 17. Staff testifies that "the artificial losses that Staff describes would not automatically lead to free profit arbitrage opportunities until market prices reached equilibrium and the purchase price was greater than or equal to the sales price." What is the basis for this claim and has Staff performed any analysis demonstrating that this statement is correct?

OPUC Response No 08:

In this context, artificial losses are focused on a step in the calculation of the DA/RT that Staff has believed historically forces purchase prices higher and sales prices lower than in actual transactions. In particular, the step 6 as identified in Staff/200 Jent/8. Staff is not aware of how a criticism in the current steps of how the DART is calculated would therefore lead to many free arbitrage opportunities.

Staff does not understand the explanation originally provided by PAC that this step of the process would lead to free profit arbitrage opportunities until market prices reached equilibrium as the step is already in place and that does not seem to be the case. Regardless, Staff assumes that there are other features in Aurora, such as transmission constraints or market **caps, which would prevent this free profit arbitrage opportunities and equilibrium from occurring.**

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OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 – PacifiCorp Data Request filed August 17, 2023

Data Request No 09:

9. Refer to Staff/800, Jent/5, line 15. Staff testifies that, "While the Commission did weigh in on the DA/RT issue in 2017. . ." Please identify the specific Commission order Staff is referencing.

OPUC Response No 09:

Staff has taken PacifiCorp's word for this reference as identified in PAC/400 Mitchell/72, which states, " The fact was recognized by the Commission explicitly when it rejected Staff's similar argument in the 2017 TAM and Staff has presented nothing here to show that the DA/RT adjustment has changed in any relevant way since its argument was rejected seven years ago." In addition, instead of stating 2017 as an absolute year, Staff in this context was referring to the 2017 TAM and PAC's comments regarding the previous Commission decision on the DA/RT adjustment.

Date: August 31, 2023

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 200
PORTLAND OR 97232
datarequest@pacificorp.com

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION

Docket No. UE 420 – PacifiCorp Data Request filed August 17, 2023

Data Request No 10:

10. Refer to Staff/1000, Anderson/12, lines 3 – 16. Staff describes the level of coal modeled at the Hunter and Huntington plants and explains that Staff's conclusion described in its opening testimony has changed. Please confirm that Staff has not performed any analysis to verify its new finding. If Staff has performed this analysis, please provide it.

OPUC Response No 10: CONFIDENTIAL

Staff's finding, that the shadow prices on the 2024 TAM minimum take fuel constraint are misleading, did not require any analysis. The logic behind the finding is that shadow prices on the upper limit to the Tier 0 fuel constraint will usually be positive when [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] if given the chance.

In this context, Staff refers to the "Fuel" constraints in the Constraint_Type column in Aurora's Constraint_Summary table. Staff is not referring to the "FuelMin" constraints in that same column.

Date: August 31, 2023

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FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 – PacifiCorp Data Request filed August 17, 2023

Data Request No 11:

11. Refer to Staff/1000, Anderson/17, lines 4 – 5. Staff testifies that the impact of the Washington Cap and Invest Program is an "issue to be a state energy policy and as such should be entirely born by Washington per MSP guidelines." What is the basis for this conclusion? In particular, please identify the relevant provision in the 2020 Protocol that Staff has relied on and provide a detailed explanation of why Staff believes the identified provision of the 2020 Protocol governs.

OPUC Response No 11:

Section 5.8 of the MSP provides:

> ***Costs and benefits resulting from a State-specific initiative will continue to be allocated and assigned on a situs basis to the State adopting the initiative*. Historically, these have included, but are not limited to, programs such as incentive programs and customer and community energy generation programs, but have not included local fees or taxes related to the ongoing operation of existing transmission and generation facilities within a State. As new issues arise, PacifiCorp will bring each issue to the MSP Workgroup to discuss whether each issue is a State-specific initiative, and, if not, whether a different allocation method is appropriate. (Emphasis added.)**

The State of Washington has described its Climate Commitment Act as duplicative of its Clean Energy Transformation Act (CETA). CETA requires electric utilities serving customers in Washington to have 100 percent renewable or non-emitting resources by 2045. To avoid imposition of duplicative energy costs from the CCA and CETA on Washington utility retail customers, the CCA provides utilities no-cost allowances to mitigate the cost burden:

> **"[T]he Clean Energy Transformation Act, Chapter 19.405 RCW, requires electric utilities serving customers in Washington to have portfolios that are greenhouse gas**

> **neutral by 2030 and 100 percent renewable or non-emitting by 2045. RCW 19.405.010(2). This is no small task and it will require significant investment on the part of the utilities. Those investments will be passed along to each utility's ratepayers as the required change-over to all renewable and non-emitting resources are reflected in rates. Adding Climate Commitment Act compliance on top of these existing obligations would create a duplicate mandate on utilities, further increasing costs to consumers absent legislative intervention. As a result, the Legislature made the policy decision in the Climate Commitment Act to ensure that compliance with the Act would not interfere with clean energy obligations or result in duplicative consumer energy costs from these burdens. RCW 70A.65.120(1). Specifically, the Act provides that those utilities subject to the Clean Energy Transformation Act are eligible for no-cost allowances "in order to mitigate the cost burden of the program on electricity customers."[1]**

Consistent with Section 5.8 of the MSP, Staff believes the costs of the CCA should be allocated and assigned on a situs basis to the State adopting the initiative until the CCA is examined by the MSP workgroup and consensus is reached on the appropriate allocation. Absent that, the appropriate allocation would be determined in the negotiation of the next Protocol.

Staff acknowledges that PacifiCorp states the CCA is a tax like other taxes imposed on utilities and allocated on a system basis. However, the State of Washington has defended claims the CCA violates the dormant commerce clause by arguing the CCA is duplicative to its CETA, which is not a tax. While taxes adopted by States have been allocated on a system basis, Staff does not believe it is appropriate to accept allocation of this legislation without subjecting it to the review allowed by the MSP.

The adjustment associated with this argument is misstated at Staff/100, Anderson/17. The correct adjustment is to remove all the Oregon-allocated CCA costs in PAC's TAM filing, which are currently forecast to be $20,943,596.

Staff's adjustment removing all CCA costs was not in its Opening Testimony. Staff's proposed adjustment removing all CCA costs was determined after further review and analysis concerning the appropriate treatment of the costs under the MSP. This adjustment is separate and alternative to the other Staff proposed adjustment to PAC's CCA costs.

---

[1] *INVENERGY THERMAL LLC, and GRAYS HARBOR ENERGY LLC, Plaintiffs, v. LAURA WATSON, in her official capacity as Director of the Washington State Department of Ecology, Defendant*, Defendant's FRCP12(c) Motion to Dismiss, February 16, 2023.

Date: August 31, 2023

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FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 – PacifiCorp Data Request filed August 17, 2023

Data Request No 12:

12. Refer to Staff/1000, Anderson/9, line 9. Please explain and provide all analysis supporting the calculation of Staff's recommended $400,000 disallowance.

OPUC Response No 12:

This adjustment is meant to reflect the possibility of a carbon tax or other price on carbon that would affect the cost of generation at Huntington. The carbon price per ton is assumed to be set at the Social Cost of Carbon (using a 3 percent discount rate). This is multiplied by the number of tons of CO2 expected to be emitted by Huntington in 2024. EIA's estimate of 2.26 pounds of CO2 per kWh of coal generation was used.[1] The total cost is then multiplied by .01 to represent the risk of such a policy being implemented in the near term to arrive at a value of approximately $400,000.

Please see Staff/1001, Anderson/2 and the attached Excel version of Staff/1001, Anderson/2.

[1] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11

[redacted]

UE 420 - OPUC Response to PacifiCorp 2nd Set of Data Request
Page 1

Date: August 31, 2023

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PACIFICORP
825 NE MULTNOMAH STREET STE 200
PORTLAND OR 97232
datarequest@pacificorp.com

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 - PacifiCorp Data Request filed August 17. 2023

Data Request No 13:

13. Staff/1000, Anderson/11, lines 1 8 - 22, Anderson/12, lines 1 - 2. Please explain in detail and provide all analysis supporting the quantification of Staff's proposed downward adjustment.

OPUC Response No 13:

This adjustment is equal to ten percent of Oregon's share of the total cost of coal from Gentry in 2024. Confidential workpapers demonstrating the calculation are attached.

This adjustment reflects Staff's estimate of the unknown efficiencies and improvements that could be made by coal suppliers if they were better informed about PacifiCorp's coal requirements. It is also inclusive of the unknown efficiencies that could be gained if PacifiCorp negotiated for improved flexibility in its Hunter coal contracts to [BEGIN HIGHLY CONFIDENTIAL] [redacted]. [END HIGHLY CONFIDENTIAL].

REDACTED

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Date: August 29, 2023

TO:
DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 200
PORTLAND OR 97232
datarequest@pacificorp.com

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 420 – PacifiCorp Data Request filed August 21, 2023

Data Request No 15:

15. Refer to Staff/1000, Anderson/9, line 9, Anderson/11, lines 19 – 20. Please confirm whether Staff's adjustments of $400,000 related to the Huntington/Wolverine CSA and $329,000 related to the Hunter/Gentry CSA are proposed as one-time disallowances or as on-going, annual disallowances.

OPUC Response No 15:

The referenced adjustments are recommended for this TAM only. Staff may recommend similar adjustments in future TAMs.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1311

Docket No. UE 307
Order No. 16-482

September 1, 2023

ORDER NO. 16 482

ENTERED DEC 20 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 307

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism.	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENT

I. INTRODUCTION

In Order No. 16-418, we granted PacifiCorp, dba Pacific Power's request to update its 2017 net power costs (NPC) in a preliminary order, subject to the company's final NPC update. In this order, we describe more fully the parties' positions and the rationale for our decisions in that order.

We also direct PacifiCorp to delay filing of its long-term fuel supply plan for the Jim Bridger coal units.[1] Instead, we direct PacifiCorp, Staff, and the parties to informally meet and discuss (1) the information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for the Jim Bridger coal units in future Transition Adjustment Mechanism (TAM) proceedings, as well as (2) whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal-fired units. We direct Staff to report back to us on the results of those discussions, with any recommendations, at the January 24, 2017 Public Meeting.

We also direct PacifiCorp, Staff, and parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments,

[1] In Order No. 13-387, we directed PacifiCorp to prepare a periodic fuel supply plan that compares affiliate mine fuel supply to other alternative fuel supply options, including market alternatives, to facilitate implementing prudence and affiliate transaction standards in future rate proceedings. PacifiCorp made two filings in its 2015 TAM in docket UE 287: first, as part of its initial filing, PAC/201 described the process it would use to prepare plans for Jim Bridger; second, as a compliance to our order approving the 2015 TAM. PacifiCorp filed the long-term fuel supply plan on December 30, 2015.

(2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation.

With respect to the first two issues, our intent is for PacifiCorp to describe its modeling approach in detail during the workshops to facilitate the parties' deeper understanding of these issues. We expect parties challenging PacifiCorp's modeling choices to engage in these discussions in order to fully understand the rationale behind the adjustments. Our goal is to create an improved evidentiary record on these disputed issues going forward. While the workshops are intended to be informational in nature, parties may also use the workshops to discuss whether any adjustments to PacifiCorp's existing methodologies may be appropriate. With respect to the REC issue, the parties should discuss whether there is a reasonable method to value RECs based on delaying the time when PacifiCorp is required to take any substantive action to ensure RPS compliance, as discussed later in this order. Staff is to report back to us on the results of these workshops before PacifiCorp's 2018 TAM is filed.[2]

In addition, to help the Commission and the parties to more fully understand PacifiCorp's direct access opt-out charge during the next TAM proceeding, we direct PacifiCorp to provide a historical time series of fixed generation costs broken down by its components (e.g., capital, O&M) as a check on the reasonableness of its forecasts. PacifiCorp should include this information in its next TAM filing.

As a result of our decisions, PacifiCorp's final compliance filing for its 2017 NPC shows Oregon allocated costs of $350.2 million. This translates to an overall annual revenue increase of $11.7 million or approximately 0.9 percent. PacifiCorp's indicative update removed the cost of avian curtailments, as directed by our preliminary order, and also moved all production tax credits from base rates to NPC, as agreed to by Staff and the company.[3] The final update filing shows 2017 power costs of $25.36 MWh.

II. BACKGROUND

PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of power costs 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

[2] We do not seek recommendations from Staff based on this set of informational workshops but simply a report on the parties' discussions.

[3] As authorized by Section 18(b) of SB 1547, PacifiCorp's initial filing contained a $5.0 million revenue requirement increase to account for expiring PTCs at several company-owned facilities. To allow the PTCs to be more easily updated in future TAM filings, Staff and PacifiCorp subsequently agreed to account for the PTC variance by removing PTCs from Schedule 200—a rate that reflects the company's fixed generation costs that was last set in the 2014 rate case in docket UE 263—and instead include the 2017 PTCs in the TAM NPC, Schedule 201.

forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's power costs for the upcoming year.

PacifiCorp projects its NPC using an optimized production cost model called Generation and Regulation Initiatives Decision Tools (GRID), which simulates the operation of PacifiCorp's power system on an hourly basis. GRID receives inputs representing PacifiCorp's system, such as load, resources available to serve the load, and transmission constraints. The GRID model calculates the least-cost solution to balance PacifiCorp's load and resources each hour while meeting system reliability and operational constraints. In that sense, GRID is optimized for perfect efficiency while maintaining system reliability. The company makes adjustments to reflect real life operations to achieve a more realistic net power forecast.[4]

This year, PacifiCorp's reply update projected 2017 NPC on an Oregon-allocated basis of \$375.5 million, \$16.2 million higher than the 2016 TAM, for an overall average rate increase of 1.3 percent. PacifiCorp explains that its NPC has increased due to decreased wholesale sales revenue, increased qualifying facility (QF) costs, and a true-up of production tax credits (PTCs).

The Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Noble Americas Energy Solutions LLC (Noble Solutions) intervened in this proceeding, and Commission Staff also participated. All parties filed testimony and briefs. A hearing was held on August 29, 2016.

The parties request several adjustments to PacifiCorp's filing:

- Staff, ICNU, and CUB raise several coal related issues, including PacifiCorp's decision to use coal purchased from an affiliate to fuel the Jim Bridger plant, the company's minimum-take provisions in its coal contracts, and a coal plant dispatch modeling adjustment.

- Staff, CUB, and ICNU recommend rejection of PacifiCorp's system balancing adjustment DART, which increases the NPC forecast by \$9.0 million on an Oregon-allocated basis.

- Staff and CUB contend that PacifiCorp has underestimated and improperly quantified EIM benefits of \$4.41 million on an Oregon-allocated basis.

[4] Tr. Vol. 1 at 43-44 (Aug 29, 2016).

- Staff requests an adjustment of approximately $65,000 on an Oregon-allocated basis to remove from NPC the costs associated with lost energy from avian protection curtailments.

- Staff and CUB contend that PacifiCorp overestimates new QF contracts, thereby improperly increasing its NPC, and propose that the company discount new QF contracts by historical success factors.

- Noble Solutions asks that the transition adjustments include a credit for the value of RECs freed up by departing direct access customers, and also seeks an adjustment to the opt-out charge in the five-year program.

In reviewing the TAM, PacifiCorp has the burden of proof to show that its proposal is fair, just and reasonable.

III. DISCUSSION

A. Overview

In our preliminary order, we found that PacifiCorp justified its 2017 NPC with evidence in the record that was not adequately rebutted by the parties. In this order we explain why we decline all adjustments other than Staff's avian curtailment proposal.

We also explain our next steps with the TAM. As noted previously, we direct Staff to report back to us by the end of January 2017 on the results of discussions regarding PacifiCorp's coal fuel-supply plans, and before the next TAM on the results of workshop discussions regarding three GRID issues.

B. Coal Costs, Contracts, and Modeling

Staff, ICNU, and CUB challenged several aspects of the company's forecasted coal costs. First, Staff and ICNU challenge PacifiCorp's projected costs to fuel the Jim Bridger coal plant, each alleging that continued reliance on affiliated Bridger Coal Company (BCC) is more expensive than market alternatives. Staff recommends a prudence disallowance, asserting PacifiCorp did not fully consider market alternatives in its long-term planning. ICNU takes a different approach, invoking our lower-of-cost-or-market rule to request that we reprice BCC coal. Next, CUB challenges the prudence of several recent supply contracts that contain provisions committing PacifiCorp to minimum coal volumes. Finally, Staff objects to the way PacifiCorp manually adjusted GRID to account for these minimum-take provisions, deeming it a modeling change prohibited by the moratorium in last year's TAM.

1. Prudence of 2017 Fuel Strategy for Jim Bridger Coal Plant

In 2017, PacifiCorp projects it will continue to source fuel for the Jim Bridger plant mostly from BCC, which has provided "mine mouth" coal to the plant since 1974. In recent years, PacifiCorp has acquired two-thirds of the plant's fuel from the adjacent BCC mine and one-third from the Black Butte mine 20 miles away. For 2017, PacifiCorp projects sourcing 65 percent from BCC, 30 percent from Black Butte, and 5 percent from the Powder River Basin (PRB) mines 400 to 600 miles to the north.

PacifiCorp's most recent fueling plan, the "Long-Term Fuel Plan" filed with the Commission in 2015, targets a transition to greater reliance on PRB coal starting mid-2023. PacifiCorp estimates it will take up to six years to permit and construct the infrastructure necessary to receive and burn large volumes of PRB coal. For the plant to burn entirely PRB coal in 2017, PacifiCorp states, it would have had to change its fuel plan during 2013 at the latest, to begin an expedited conversion process in 2014.

a. Parties' Positions

Staff argues that the company's 2017 fuel strategy is not least-cost, least-risk. Staff maintains that, had PacifiCorp prudently undertaken a comprehensive long-term analysis in 2013, it would have discovered that lower-priced market options were viable, including coal from PRB mines. Instead, argues Staff, PacifiCorp engaged in short-term analysis and relied too heavily on an outdated figure for the cost of needed retrofits. Staff asks for a $23.5 million (Oregon allocated) disallowance to represent the amount customers would have saved in 2017 NPC by a switch to PRB coal in 2017.

PacifiCorp responds that in 2013, it made a prudent decision to sustain its historical BCC/Black Butte fueling strategy. This strategy was thoroughly vetted, PacifiCorp presses, through the course of successive TAM proceedings, including our finding in October 2013 in the 2014 TAM, that the proposed BCC/Black Butte fuel strategy was reasonable and prudent.[5] PacifiCorp maintains the prohibitively high estimate at the time from consultant Black and Veatch for the cost of needed retrofits consistently rendered PRB uneconomic compared to available alternatives.

Leading up to (and after) 2013, PacifiCorp maintains, it prepared a BCC mine plan with a 10-year planning horizon to develop a strategy for least-cost, least-risk fueling of the Jim Bridger plant. And every two years, it developed a more comprehensive life-of-plant fueling plan for the Integrated Resource Plan (IRP) (including the 2011, 2013, and 2015 IRPs) to assess and determine the least-cost, least-risk fueling option. These plans, PacifiCorp argues, included PRB

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

as a potential source. Staff counters that the evaluations and analysis in these plans are fundamentally inadequate to support a finding that the company's strategy for the 2017 TAM is least-cost, least-risk.

After 2013, PacifiCorp attests, it continued to look at PRB coal in its long-term planning. In June 2014, it issued a Request for Proposals (RFP) for coal to serve the Jim Bridger plant, which it sent to suppliers including PRB mines. This resulted in the current Black Butte contract, which proved lower cost than PRB. And in July 2014, it completed a new long-term fuel plan for its 2015 IRP that reflected PRB as a long-term source for the plant. This plan, explains PacifiCorp, evolved into the Long-Term Fuel Plan filed with the Commission in 2015 that targets 2023 to start the transition to PRB coal. PacifiCorp describes this plan as a new tool that added to its existing planning.

PacifiCorp allows that BCC unit costs have increased relative to last year's TAM, but says this was driven by market changes in early 2016. By the reply update, PacifiCorp points out, market conditions had returned to a more normal state and forecasted BCC unit costs decreased as plant dispatch increased. PacifiCorp contends that Staff's long-term analysis favors PRB coal only because of errors and incorrect assumptions including Staff's "facially unreasonable" transportation charge, use of a 2015 figure for the cost of retrofits, and unreasonable amortization periods for the retrofits and plant.

PacifiCorp suggests rejecting Staff's adjustment and opening an expedited planning docket to consider the least-cost, least-risk fuel supply plan for the Jim Bridger plant.

b. Resolution

In a prudence review, we look at the objective reasonableness of a decision at the time it was made, considering the information then available to the utility.[6] We examine all actions of the utility—including the process that the utility used to make a decision.[7] We do not require perfection; just that the utility's actions were reasonable.[8]

Here, considering the evidence of what PacifiCorp knew or should have known in 2013, we conclude that PacifiCorp was reasonable in not accelerating conversion to PRB coal at that time. We approved the company's fuel strategy that same year in the 2014 TAM, finding BCC and Black Butte provided a reasonable, stable coal supply. PacifiCorp has demonstrated that it considered market alternatives to BCC coal before, during, and after 2013 in its various approaches to long-term planning for the plant, but consistently found the cost of conversion to

[6] *In the Matters of PacifiCorp*, Docket Nos. UM 995, UE 121, and UC 578, Order No. 02-469 at 4-5 (Jul 18, 2002).
[7] *In re PacifiCorp*, Docket No. UE 246, Order No. 12-493 at 26 (Dec 20, 2012).
[8] *In the Matter of Portland General Electric Company Application to Amortize the Boardman Deferral*, Docket No. UE 196, Order No. 10-051 at 11 (Feb 11, 2010).

PRB coal too costly. The estimate that PacifiCorp had at the time from consultant Black and Veatch for the cost of needed retrofits rendered PRB uneconomic compared to available alternatives.[9] We recognize that integrating PRB coal supply at the Jim Bridger plant is a complicated undertaking that will involve avoiding contractual commitments, closing the BCC mine, and solving operational challenges and would not expect the company to turn on a dime to make this irreversible conversion.

However, our inquiry does not end there, as we will revisit PacifiCorp's fueling decisions annually in the TAM. Staff and parties have stated a desire for additional information and analyses to more fully evaluate the long-term fuel supply plan for the Jim Bridger plant. Accordingly, we direct PacifiCorp to delay filing of its long-term fuel supply plan for the Jim Bridger coal units. Instead, we direct PacifiCorp, Staff, and the parties to informally meet and discuss: (1) the information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for the Jim Bridger coal units in future TAM proceedings, as well as (2) whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal-fired units. We direct Staff to report back to us on the results of those discussions, with any recommendations, at our January 24, 2016 Public Meeting.

2. Application of Lower-of-Cost-or-Market Rule

a. Parties' Positions

ICNU contends that we should apply our Lower-of-Cost-or-Market-Rule found in OAR 860-027-0028 to reduce the price of BCC coal in the company's forecasted 2017 NPC. The rule requires that services or supplies transferred or provided from an affiliate are recorded at the lower of the affiliate's cost or the market rate. "Market rate" is defined as the lowest price that is available from nonaffiliated suppliers for comparable services or supplies. ICNU claims that PRB coal is lower-cost than affiliated BCC coal for 2017, even after accounting for the needed retrofits and amortization of the undepreciated mine investment. ICNU recommends that we apply the rule here to reduce the forecasted costs related to BCC coal deliveries by $6 million (Oregon allocated).

ICNU proposed a similar adjustment in the 2014 TAM.[10] In that case, ICNU proposed to reprice BCC coal at the 2014 contract cost of Black Butte coal. PacifiCorp argued that sufficient additional volumes from Black Butte were not available because the mine did not have sufficient excess capacity, and even if it did, the price would be higher than the existing contract price. We

[9] The total estimated cost is provided in confidential PAC/1002, Ralston/6.
[10] Order No. 13-387 at 7.

rejected ICNU's adjustment, finding ICNU's use of the 2014 contract price as a substitute price to be unpersuasive.

In this proceeding, ICNU refines its adjustment and argues that what matters is not that the utility can literally substitute the market product but instead that the market price is a fair comparison. ICNU maintains we have never specifically found the rule requires the market alternative to be physically available to replace the affiliate supply. To find otherwise, ICNU cautions, could allow a utility to avoid application of the rule by deferring investments that would otherwise be in the best interest of customers.

Staff supports ICNU's adjustment, attesting that it and ICNU have presented comprehensive analysis that demonstrates PRB coal is a viable, lower-cost market alternative to BCC coal. Staff adds that we have consistently evaluated the reasonableness of BCC costs by comparing those costs to market alternatives.

PacifiCorp argues that, like ICNU's adjustment in the 2014 TAM, the market alternative here cannot actually replace BCC coal in 2017. Due to the retrofits needed to handle PRB coal, PacifiCorp explains, it is impossible for the company to rely on the volume of PRB coal that would be needed. The plain and ordinary meaning of "available," PacifiCorp argues, is *present, ready for immediate use, accessible, obtainable*. PacifiCorp insists that harm to customers can only occur if the utility could have reduced its costs but chose instead to rely on the affiliate supplier. Even if the Jim Bridger plant could physically accept PRB coal in 2017, PacifiCorp continues, it would not be lower cost. ICNU's pricing, PacifiCorp argues, unreasonably changes the amortization period from 4 years to 13 years and lowers the return on the company's undepreciated investment in the mine.

b. Resolution

Based on the evidence in the record, we are not persuaded that we should substitute a market rate for BCC pricing in 2017. At present, the PRB market rate that ICNU proposes is not actually available to PacifiCorp to fuel the Jim Bridger plant because the company has not yet retrofitted the plant to receive and burn high volumes of PRB coal. Consequently, this adjustment relies on the same issue as Staff's proposed adjustment—whether as of late 2013, a reasonable utility would have invested PacifiCorp's share of the investment required to make the switch to PRB coal in 2017. We find in this order that, considering the evidence in the record of what PacifiCorp knew or should have known in 2013, the company was reasonable in adhering to its historical fueling strategy. As a result, it would be inconsistent to hold PacifiCorp accountable for a market rate that would be available only if it had decided differently in 2013.

3. ***Prudence of Coal Supply Contracts with Minimum-Take Provisions***

PacifiCorp's 2017 NPC include three coal supply contracts executed since PacifiCorp's 2013 IRP (i.e., 2015 and beyond). These comprise a coal supply agreement for the Jim Bridger plant that expires in 2017, a supply agreement for the Dave Johnston plant that expires in 2018, and long-term supply agreement for the Huntington plant. All of these contracts have a minimum-take, or "take-or-pay," provision that requires PacifiCorp to purchase a minimum specified amount of coal over a given time period.

a. Parties' Positions

CUB suggests it was imprudent for PacifiCorp to make this type of binding and ongoing commitment to minimum coal volumes given the uncertainty of federal, environmental, and regulatory constraints. CUB recommends disallowing all costs and impacts of the minimum-take provisions in these recent contracts. This would require that the GRID model be rerun with the minimum of either the market cost of coal or the contract price input as the incremental cost of coal.

Staff shares CUB's concern that the prudence of entering into contracts with take-or-pay provisions is questionable. Still, Staff believes there is not sufficient evidence on the record to address the prudence of these contracts and suggests delaying any determination until the company's 2017 power cost adjustment mechanism (PCAM) proceeding.

PacifiCorp responds that these provisions are a component of virtually all cost-effective coal supply agreements and constitute the consideration required to obtain favorable pricing. These guarantees provide investment security for the seller, PacifiCorp explains, ensuring steady revenue for continued investment in the resources necessary to supply coal. The alternative, PacifiCorp states, would be to rely on the spot market for coal, thus exposing customers to significant risk in supply reliability and price variability. PacifiCorp states it has never relied exclusively on the spot market and doing so would be categorically imprudent.

b. Resolution

We are not persuaded by CUB's claim that committing to coal supply agreements with these minimum-take provisions was imprudent by PacifiCorp. As PacifiCorp points out, two of these contracts are short-term, expiring in 2017 and 2018. Moreover, PacifiCorp provided evidence that these provisions are typical in coal supply agreements and that, without entering into supply agreements with these types of provisions, it would have to rely on the spot market with the attendant supply and price risk.

4. Modeling of Minimum-Take Provisions in 2017 TAM

When PacifiCorp prepared the initial filing for this TAM proceeding, market conditions were such that it had to manually adjust its GRID model to increase the dispatch of plants subject to minimum-take provisions. To do this, it manually adjusted the incremental cost of coal to achieve the overall least-cost dispatch of the entire coal fleet while meeting the minimum-take obligations for each plant. The GRID model does not innately account for this type of contract provision. By the time of the reply update, there was no longer a need to make this adjustment as higher wholesale electricity prices had naturally increased the forecasted dispatch of the affected plants.

a. Parties' Positions

Staff asserts that PacifiCorp's manual adjustment constituted a modeling change prohibited by the moratorium we imposed last year on changes in the 2017 cycle.[11] Staff argues that PacifiCorp has not demonstrated that parties were notified of this change in this proceeding or in previous TAMs. Staff recommends postponing this change for a year to allow Staff to fully analyze the 2016 TAM changes, consistent with the intent of the moratorium. For purposes of 2017 NPC, Staff proposes that fuel cost could be calculated at the marginal contract or spot price, resulting in a $3.9 million (Oregon allocated) reduction.

PacifiCorp responds that its approach to modeling minimum-take provisions through manual adjustment to the incremental cost of coal is consistent with past TAM proceedings and has been part of the GRID model since 2005. The modeling predated the TAM Guidelines, it explains, and it did provide notice when it revised GRID in 2005. The effect was more pronounced this year, PacifiCorp explains, because the historically low-market prices for natural gas and electricity resulted in decreased coal plant dispatch in the initial filing. PacifiCorp points to specific plants for which it reduced the incremental contract costs in the 2015 and 2016 TAMs to increase the volume used by the plants beyond the minimum-take volume.

PacifiCorp also challenges the amount of Staff's adjustment. First, PacifiCorp suggests Staff quantified its adjustment based on the minimum-take provisions implicated in the initial filing, not the reply update, where the adjustment would now be zero. Second, PacifiCorp suggests that Staff double-counts the impact at the Jim Bridger plant because Staff separately included the same adjustment in its proposed disallowance for Jim Bridger coal supply.

[11] *See In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec 11, 2015) (imposing moratorium on modeling changes in the 2017 cycle to provide time for Staff, parties, and Commissioners to better understand recent changes).

b. Resolution

We are not persuaded by Staff's argument that this is an improper modeling change. PacifiCorp has demonstrated that this practice is consistent with past TAM proceedings. The company cites specific plants for which it made these types of adjustments in past TAMs. The impact is more pronounced this year, it explains, because of low electricity market prices at the time it prepared its initial filing.

C. Day-Ahead Real-Time Balancing Transactions (DART Adjustment)

In the 2016 TAM, we approved PacifiCorp's system balancing transactions adjustment (DART adjustment).[12] The DART adjustment includes two components to capture system balancing costs that are neither included in the company's forward price curve nor modeled in GRID. Under this adjustment, PacifiCorp first increases the overall prices in GRID for forecasted system balancing sales and purchases to recognize that the company is a price-taker—that is, paying more in heavy load hours than average actual market prices, and selling for lower than average during light load hours ($5.4 million).[13] Second, the company increases the volumes of balancing transactions by 30 percent to account for the use of monthly, daily, and hourly products ($3.6 million).[14]

In approving this adjustment last year, we agreed that PacifiCorp's average balancing purchase prices systematically exceed its average balancing sales prices. We also found that GRID understated the volumes of balancing transactions. For these reasons, we approved the DART adjustment to improve forecast accuracy.

Staff, CUB, and ICNU contend the DART adjustment contains numerous flaws and recommend we reverse our decision. They propose we reject the DART adjustment now, and then allow the parties to work on an improved methodology. We summarize their arguments below.

1. Arbitrary Price Adders

Staff claims the price adder component of the DART adjustment is unrealistic and arbitrary. For example, Staff states the price adjustment is inflated by averaging the price difference over a monthly period, rather than a shorter, more accurate time period. Staff points out that the company has the ability to use a more granular time period because the prices in GRID are reshaped by day of the week and hour of the day to match historic patterns. PacifiCorp responds that the monthly time horizon matches the time periods used in the forward price curve.

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[12] *Id.*.
[13] PAC/400, Dickman/21.
[14] PAC/100, Dickman/19; PAC/400, Dickman/22.

Staff also challenges the use of separate purchase and sale prices for each hour. Staff states that there is only a single clearing price in any given market at any one point in time, and that GRID already differentiates market price into periods of higher and lower prices. PacifiCorp responds that the use of two market prices is necessary because GRID is either buying or selling in each hour, and that the use of separate market prices gives GRID better signals. Staff disagrees and believes this misrepresents GRID, because PacifiCorp often makes purchases at one hub and sales at another hub. Staff explains that, with DART, PacifiCorp increases the price of the buying hub above forecast and decrease the price of the selling hub below forecast. Moreover, Staff emphasizes that PacifiCorp agrees with Staff, ICNU, and CUB that a single price, when properly correlated, would accomplish the objective of PacifiCorp's two-price system by representing market prices within GRID.

ICNU and CUB contend that the company should use the data it already has on production capacity and capacity factors to determine when the market prices that it will pay are above or below average. CUB states that the company has been uncooperative regarding alternative approaches to DART.

2. *Unsupported Increases to Market Transaction Volumes*

Staff asserts that PacifiCorp's volume component adjustment is arbitrary. Staff argues that adjustment uses historic market transactions inequitably by pushing historical costs into NPC without offsetting historical benefits such as variations in fuel price. PacifiCorp responds that it is properly using normalized historical results.

Staff states that the DART price adders eliminate the value of arbitrage transactions. Staff explains that arbitrage transactions should reduce NPC through the variance between purchase price at one hub and sale price at another hub, or the difference between hubs. Staff also distinguishes the arbitrage transactions that PacifiCorp includes, which are different because they capture the price difference between hub and market price (not hub to hub). PacifiCorp responds that the adjustment properly includes arbitrage transactions and excludes hedging transactions.

CUB argues that PacifiCorp's volume adjustment improperly uses pre-EIM data. PacifiCorp responds that EIM participation has not decreased the company's system balancing costs, because under the EIM PacifiCorp balances its system 60 minutes in advance instead of 30 minutes. PacifiCorp adds that counterparties do not want to part with resources that might be needed and there are higher prices for purchases.

3. Double Counting with Integration Costs

ICNU contends that, if we retain the DART adjustment, then day-ahead wind and load integration costs should be removed from NPC because they are being double counted ($1.9 million reduction). ICNU explains that the DART adjustment incorporates actual historical purchases and sales, including the real costs associated with day-ahead wind and load integration from those historical transactions. ICNU adds that the day-ahead integration costs relate to the balancing cost for the difference between the day-ahead resource commitment and the actual commitment of wind and load. ICNU states that the DART adjustment calculates the $/MWh cost of system balancing but does not remove the transactions that were made for the purpose of day-ahead load and wind integration.

PacifiCorp responds that inter-hour integration costs calculated in the 2014 wind integration study are the system balancing costs primarily resulting from differences between day-ahead unit commitment and actual dispatch commitment of gas plants, not market transactions considered in the DART.

4. Resolution

We reaffirm and uphold our decision in Order No. 15-394 approving PacifiCorp's system balancing adjustment. The DART adjustment—while not perfect—reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs.

We decline to adopt Staff and CUB's recommendation that we eliminate the adjustment now and direct PacifiCorp and parties to work on substitute modeling adjustments to better simulate buy and sell balancing transactions for future TAM proceedings. No persuasive evidence was offered to convince us that our decision last year was in error. We also find that four years of data is sufficient to generate a normalized result and that PacifiCorp's adjustment is based on an analysis of a reasonable set of transactions.[15]

Similarly, we decline ICNU's proposed wind integration adjustment and accept PacifiCorp's explanation that the wind integration study and DART are capturing different system costs related to balancing and are additive. The company explains that the day-ahead integration charge primarily accounts for additional operating reserves and less than optimal resource dispatch due to day-ahead forecast uncertainty.[16] The DART adjustment is designed to capture

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[16] PacifiCorp Reply Brief at 33 (Oct 5, 2016).

only the price difference between the average market price and the company's actual prices for balancing transactions. DART is initially applied as an adder to increase market prices, and the wind integration costs are applied as a separate out-of-model adjustment for the added integration costs of wind integration.

Last, as further explained in our discussion of next steps below, we direct PacifiCorp, Staff, and other parties to meet informally to examine the DART adjustment in detail and provide parties opportunities to offer and discuss potential alternative modeling approaches.

D. Energy Imbalance Market (EIM) Benefits

In the 2017 TAM, PacifiCorp estimates $4.84 million in inter-regional EIM benefits, $1.13 million in flexibility reserve benefits, and $1.56 million in EIM costs, all on an Oregon-allocated basis, for a net 2017 benefit of $4.41 million for Oregon customers.[17]

Staff and CUB dispute PacifiCorp's estimates for inter-regional benefits. They believe the estimates should be increased so they are closer to CAISO's calculation and that *intra*-regional benefits should also be added to the TAM. Staff and CUB also believe that the company's methodology is too complex and lacks transparency, and believe that a separate, independent investigation on the modeling of EIM benefits is necessary.

1. Inter-regional Benefits, Methodology, and Transmission Capacity

Staff and CUB maintain that the company's calculation of EIM inter-regional benefits grossly understates actual benefits, and that customers should receive the actual benefits that are reported by CAISO for the current year.

Staff argues that PacifiCorp's inter-regional EIM benefits are understated because the company is not using actual production costs. Staff believes actual production costs consist of the marginal cost, or the variable cost of the power plus operating and maintenance costs. Staff maintains that PacifiCorp uses bid prices for thermal resources, replacement costs for hydro units, and a value for wind facilities based on curtailment payments, lost PTCs, and the value of the lost RECs. Staff believes that for the renewable hydro and wind facilities, the marginal cost to produce a MWh should be zero. Staff explains that PacifiCorp's calculations use a bottom-up approach with a tremendous amount of data and prices instead of actual production costs.

[17] PAC/400, Dickman/56; PAC/405, Dickman/1. The parties discuss EIM values on a total company basis, and any total company figures have been adjusted by Oregon's 2017 allocation factor of 25.230 percent for purposes of this order.

CUB argues that the company underestimates EIM benefits by limiting EIM transfers based on the available transmission in the forecast test period. CUB and Staff recommend that we adopt the method employed by the company for NV Energy that uses historical sales, not historical transmission allocation to forecast EIM inter-regional benefits on an annual basis.

With regard to Staff's arguments, PacifiCorp responds that its filing uses the same methodology we found reasonable in the 2016 TAM, and is further refined to identify the specific incremental resources used. PacifiCorp explains that benefits of exports are equal to the revenue received less the production cost of the resource. Benefits of imports are the import expense less the expense of the generation that would have been dispatched otherwise. The production cost used is the marginal cost to produce an additional megawatt-hour at a given resource, which is equal to the resource bids submitted to the EIM. In response to Staff and CUB's argument that the EIM bids include adders, the company states that the only adder is a small percentage adjustment to account for the possible change in natural gas prices or other costs typically incurred over time such as pipeline charges.

In response to CUB's arguments, PacifiCorp explains that EIM exports use limited California-Oregon intertie transmission capacity, so if NPC includes forward transactions at the California-Oregon border, there will be less transmission available for EIM exports. PacifiCorp states that it used the actual historical EIM benefits, divided by the total transmission that was available for the EIM during the historical period, and expressed in dollars per megawatt-hour of available transmission. This margin is then applied to the transmission in the 2017 TAM that is available for EIM.[18] PacifiCorp states this approach ensures that the same transmission capacity is not improperly used for both sales to the California-Oregon border market and EIM.

2. *Intra-regional Benefits*

Staff and CUB argue that PacifiCorp should also include a third type of benefits—intra-regional benefits. They define intra-regional benefits as PacifiCorp's more efficient dispatch within its own balancing authority area (BAA). PacifiCorp does not include intra-regional benefits in the TAM because it states that GRID has always reflected perfectly optimized dispatch.

Staff points to CAISO's benefit calculation that includes intra-regional benefits by comparing a less efficient counterfactual dispatch to EIM dispatch. Staff believes that CAISO's counterfactual dispatch is nearly identical to GRID, because it is a less-efficient, more costly method of dispatch compared to the EIM and because it uses resources that can ramp quickly.

[18] PAC/400, Dickman/77.

CUB believes the company has not met its burden of proof that intra-regional benefits should be zero. CUB recommends that we either adopt CAISO's benefit calculation, or find that the company's forecast of zero and CAISO's forecast of $6.61 million (Oregon allocated) represent the potential range of 2017 intra-regional benefits, and use the midpoint as a reasonable estimate for ratemaking. This midpoint can be used until there is an investigation on the modeling of EIM benefits.

CUB and Staff also argue that PacifiCorp is realizing intra-regional benefits from the five-minute market that are not reflected in GRID's hourly model. CUB and Staff state that even if GRID is perfectly optimized, the sub-hourly transactions facilitated by the EIM offer more efficiencies since the EIM can dispatch across the hour, while ramping resources to meet the next hour.

PacifiCorp maintains that intra-regional benefits are inherent in the GRID forecast and imputing additional benefits is double-counting. PacifiCorp states that the intra-regional benefits are real, but they only bring actual costs closer to the ideal dispatch calculated in GRID. Regarding CAISO's calculation of intra-regional benefits, PacifiCorp states the counterfactual is not the same as GRID but is closer to the manual, less efficient pre-EIM dispatch.

3. Resolution

We accept PacifiCorp's 2017 EIM benefit calculation of $4.41 million net of costs, reflecting inter-regional and flexibility benefits on an Oregon-allocated basis, and decline the proposed adjustments.

We find PacifiCorp's estimates of inter-regional benefits reasonable. PacifiCorp refined its modeling of inter-regional benefits using 12 months of actual results and a resource stacking method that specifies the actual resources used for EIM facilitated transfers.[19] This modeling refinement plus incorporation of actual results from NV Energy participation in the EIM resulted in higher inter-regional benefits in 2017 as compared to 2016. PacifiCorp rebutted Staff's claims about the lack of use of actual production costs by showing that the resource bid prices equal the marginal resource cost (or production cost of that resource) plus a small adder that accounts for changes in certain cost drivers over time.

We find that the GRID forecast already accounts for intra-regional benefits because the model optimizes dispatch on an hourly basis. The company explains that modeling dispatch on a sub-hourly basis would yield additional benefits by claiming that modeling of five-minute dispatch would increase net variable costs. PacifiCorp also effectively rebuts the argument that the GRID and CAISO "counterfactuals" are functionally equivalent. PacifiCorp points out that the CAISO

[19] PAC/400, Dickman/71.

counterfactual aims to mimic the manual dispatch at a subset of power plants that occurred before the EIM was put in place.

In addition, we concur with PacifiCorp that it appropriately accounts for transmission constraints in its modeling and decline CUB's proposed adjustment. PacifiCorp's calculation has not changed since the 2016 TAM.

Finally, as further explained under our discussion of next steps below, we accept PacifiCorp's offer to hold workshops to discuss the company's EIM modeling in depth and provide opportunities for parties to propose refinements to those methodologies.

E. Qualifying Facility (QF) Contracts

1. Parties' Positions

CUB and Staff propose changes to how PacifiCorp models new QF contracts in the TAM. Currently, PacifiCorp uses an attestation process that was agreed to by the parties in the 2015 TAM stipulation. Under this process, PacifiCorp includes in its modeling only those new QF contracts for which the utility has a commercially reasonable good faith belief that the QF will commence commercial operations during the test period. The QF cost is then pro-rated to reflect the expected operation date.

CUB and Staff propose that this method be modified to account for the fact that, despite the attestations, not all QFs become operational by the end of the test year. CUB and Staff propose the company apply a discount factor based on the historical difference between forecasted and actual energy generation from new QFs, or, as Staff describes it, the difference between forecasted QFs becoming operational in the year and actual QFs with contracts at the beginning of the year. CUB proposes a specific discount factor—that we limit the company to 93 percent of the new QF contracts, based on past performance. ICNU supports a historical success factor.

In support of its recommendation, CUB explains that QF contracts are a significant driver of NPC increases, accounting for $99 million in total-company NPC increase this year.[20] CUB recognizes that the company must sign any QF contract presented to it at avoided cost rates. However, CUB states that, with the expectation of avoided costs decreasing in the future, QFs are rushing to get contracts signed and, under the current attestation process, customers will pay increased power costs for certain QF contracts that will not come online during the test year. In response, PacifiCorp states that it models QFs with their expected operational date, and that on average, the TAM has understated the total count of QFs and their volume of energy.

[20] PAC/100, Dickman/10; PAC/400, Dickman/11.

PacifiCorp provided information on the new QFs expected to come online in 2016, as well as year-by-year information on the total amount of system QFs forecasted and actuals, both of which show forecasts close to actuals.[21]

2. Resolution

We decline to apply any discount factor at this time for new QF contracts. As discussed above, the attestation process for QF contract costs was adopted as part of the 2015 TAM stipulation. Under that agreement, PacifiCorp confirms in its November indicative update those new QFs it reasonably believes will reach commercial operation during the rate effective period, and also updates the expected commercial operation dates to reflect project delays.[22]

We acknowledge CUB's undisputed claim that only 80 MW of the 96 MW of new QF generation that was forecasted for this year has become operational.[23] As CUB concedes, however, we do not yet have concrete data to fully evaluate the 2016 forecast accuracy, because many of the QFs are forecast to begin operation at the end of the calendar year. Because PacifiCorp has shown that, from 2008 to 2015, the company's overall QF forecast has averaged out below the actual QF production, we will allow the attestation process to continue.

We appreciate the parties' oversight of the QF costs, and will further consider this issue when additional data is available to evaluate PacifiCorp's use of the attestation method.

F. Avian Protection Compliance Adjustment

1. Parties' Positions

Staff challenges PacifiCorp's decision to reduce generation at two wind sites (Glenrock and Seven Mile Hill) to reflect anticipated energy lost from implementing avian protection curtailments to comply with a court order. Staff contends that new information shows that PacifiCorp knew or should have that avian-related curtailments were possible, and that ratepayers should be held harmless from the company's decision to proceed with developing these sites.

[21] PAC/400, Dickman/88; PAC/800, Dickman/42; PAC/805.

[22] *In the Matter of PacifiCorp's 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5, App A at 7 (Oct 1, 2014) ("Attestation for Qualifying Facility (QF) Contracts. The Settling Parties agree that the attestation included with PacifiCorp's Indicative Update in TAM proceedings will include a statement confirming that, for the executed power purchase agreements (PPAs) with new QFs included in the TAM, PacifiCorp has a commercially reasonable good faith belief that these QFs will reach commercial operation during the rate effective period based on the information known to the company as of the contract lockdown date. This attestation language does not require PacifiCorp to opine on the commercial viability of any of these QFs.").

[23] CUB/100, McGovern/21-22; PAC/400, Dickman/86.

Staff's argument is based on new evidence demonstrating that PacifiCorp knew, or should have known at the time of siting the wind farms, that there was relevant agency guidance on avoiding and minimizing avian take by wind facilities. Staff contends, although it is within PacifiCorp's discretion to abide by or ignore such guidance, ratepayers should not be disadvantaged by the company's gamble on these enforcement actions that would reduce the output of these facilities. Staff emphasizes that this information was not introduced during our earlier prudence review of these wind projects. Staff contends that there is no indication that the parties or the Commission was aware in that rate proceeding[24] that the projects were intentionally sited contrary to agency guidance, or that PacifiCorp evaluated the cost of this siting.

Staff asserts that, because we approved these projects based on the capacity factor without the avian curtailments, it would not be fair to allow PacifiCorp to reduce this capacity factor to account for these anticipated but undisclosed curtailments. To hold ratepayers harmless, Staff recommends a $249,114 total company reduction (approximately $65,000 for Oregon).

In response, PacifiCorp points to the 2016 TAM, where we rejected a similar adjustment proposed by ICNU.[25] PacifiCorp also defends it actions, indicating that the curtailments are mandated by a court order, that at the time the projects were being built, there had never been an enforcement action against a wind project, and that the parties were aware that the projects were sited in an avian sensitive area during the proceeding that brought the projects into rates.[26] PacifiCorp maintains that no party to that proceeding challenged the prudence of the projects based on avian curtailment risk and that we found both projects prudent and we should not revisit this issue.

2. *Resolution*

We accept Staff's adjustment to reduce the company's NPC forecast by approximately $65,000 on an Oregon-allocated basis, an amount that is associated with the avian curtailment costs.[27] Although we rejected a similar adjustment in the 2016 TAM, the new undisclosed evidence of PacifiCorp's actual or constructive knowledge of possible avian curtailments convince us that an adjustment is necessary to hold ratepayers harmless.[28] Our decision does not constitute a hindsight prudence review of these facilities. The company's avian curtailment costs are similar to forecasted costs associated with a plant outage, and we are limiting PacifiCorp's ability to

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[24] *In the Matter of PacifiCorp's 2009 Renewable Adjustment Clause*, Docket No. UE 200, Order No. 08-548 (Nov. 11, 2008).
[25] Order No. 15-394 at 7 ("First, PacifiCorp must comply with the court order for avian protection.").
[26] *See* PAC/800, Dickman/30.
[27] PacifiCorp NPC Indicative Update, Exhibit B at 1 (Nov 8, 2016) (removed lost energy from avian protection curtailment, decreasing net power cost by approximately $65,000 on an Oregon-allocated basis).
[28] Staff/200, Kaufman/18; Staff/205, Kaufman/18 (Wyoming plea agreement and joint statement of facts).

reduce its forward-looking NPC for reasons that the company knew or should have known about restrictions on operations at the time it was siting these wind facilities.

G. Direct Access Issues

As part of the TAM process, we establish rates for PacifiCorp's large non-residential customers that may elect to leave PacifiCorp's cost-based service and choose to receive their energy from direct access providers. Customers that participate in PacifiCorp's direct access program are subject to three potential annual cost components. All direct access customers (one-year, three-year, and five-year) are subject to a transition adjustment and a Schedule 200 fixed generation charge. Customers in the five-year program also pay an opt-out charge.

- The transition adjustment is the difference between PacifiCorp's net power cost (as reflected in Schedule 201) and the estimated market value of the electricity that is freed up when a customer chooses direct access service.[29] Currently, this is a small credit to the customer.

- The Schedule 200 charge represents the company's fixed-generation costs, updated in the TAM. A direct access customer is required to pay this as it represents PacifiCorp's stranded fixed-generation costs.

- The Schedule 296 opt-out charge, applicable to five-year program customers, is calculated by bringing forward into years one through five the projected Schedule 200 costs for years six through ten, net of projected net power cost savings attributed to the departed load.

According to Noble Solutions, a five-year direct access participant in 2017 will, in year one, receive a transition credit of $1.76 MWh, pay a Schedule 200 charge of $26.73 MWh, and pay a Schedule 296 opt-out charge of $13.37 MWh. The customer would be subject to these cost components for each of the five years of the program.

Noble Solutions requests that PacifiCorp's transition adjustment and opt-out charge be reduced in two ways. First, Noble Solutions asks that the transition adjustment be credited for the value of RECs freed up by the departing direct access customer. Second, Noble Solutions recommends that the opt-out charge in the five-year program be reduced to account for the impact of accumulated depreciation. We address each proposal separately.

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[29] OAR 860-038-0005(41) Ongoing valuation method determines the transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

1. *REC Adjustment*

a. Parties' Positions

Noble Solutions requests that the transition charges in the one-year, three-year, and five-year programs include a credit for freed-up RECs during the transition period. Noble Solutions argues that, when a direct access customer departs PacifiCorp's system, RECs that were previously acquired by PacifiCorp to serve that load are freed up for other uses.

Noble Solutions acknowledges that the direct access customer is credited for the assumed value of the freed-up energy from PacifiCorp's portfolio, but contends that the valuation method does not account for the value of renewable attributes or RECs. To properly account for these freed-up RECs, Noble Solutions request that we first value an unbundled REC at $1 each. Then, we should multiply that value by 15 percent (the RPS compliance percentage requirement for 2017 met by PacifiCorp's resources) and add $0.15 to the weighted average market price of freed-up energy in the TAM calculation. Alternatively, Noble Solutions asks that PacifiCorp transfer to the alternative electricity service supplier (ESS) the RECs that are freed up as a result of direct access, and explains that in 2015 this was approximately 31,200 RECs.[30]

In response, PacifiCorp points to last year's TAM, where we found that Noble Solutions' formula for valuing freed-up RECs assumed PacifiCorp would sell its RECs, when in fact, PacifiCorp banks its RECs. We also explained that, to the extent RECs are sold, proceeds flow back to customers, and that the net present value of any freed-up RECs is *de minimis*.[31] PacifiCorp states that our findings are still true today, and that the increased RPS obligation from SB 1547 makes it more likely that the company will continue to bank its RECs. Staff agrees and supports PacifiCorp's arguments.

PacifiCorp also asserts that there is no reliable basis to value the freed-up RECs. With the passage of SB 1547, PacifiCorp states, the valuation problem has become more intractable because RECs can have different values and there is no reasonable basis to assume which RECs were freed up by the departing customer.

b. Resolution

We decline Noble Solutions' proposed adjustments to reflect the value of reduced RPS obligations.

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[30] Noble Solutions/200, Higgins 6-7.
[31] Order No. 15-394 at 12.

In the near term, we see little or no benefit from a reduction in RPS obligation due to the loss of load from direct access. PacifiCorp has ample resources to comply with the RPS through the mid- to late-2020s; a "freed-up" REC today simply adds to the surplus of RECs that PacifiCorp already has or will have to comply with the RPS. Further, PacifiCorp has stated that it will continue to bank RECs rather than sell them, so there is no benefit to other customers from a potential sale of RECs.

Over the long run, if there is a guaranteed loss of load due to direct access, then there may be benefits to other customers by altering the point in time when PacifiCorp would need to take resource actions to comply with the RPS. However, based on the record, PacifiCorp would not need to take such action to ensure compliance with the RPS until the mid-2020s. No party has offered a reliable way to estimate the value of loss of load in that time period and we note the complexities to derive such an estimate. We also find that any reasonable estimate of benefits from that time period would be *de minimis* when discounted to today's dollars.

Finally, as further addressed below, we direct PacifiCorp, Staff, and the parties to further discuss REC valuation in the party workshops, with a focus on the potential benefits that may derive at the time PacifiCorp must take substantive action to comply with its RPS targets.

2. Consumer Opt-Out Charge

a. Parties' Positions

As noted above, the Schedule 296 Consumer Opt-Out Charge applies to the five-year program, and is a projection of what Schedule 200, fixed generation costs, would be for years six through ten brought forward into years one through five. Noble Solutions asserts that, when calculating this charge, fixed generation investments in Schedule 200 should be frozen after year five and should decline each year from year six through ten to reflect accumulated depreciation. Noble Solutions acknowledges that we declined this adjustment in the 2016 TAM order, but has appealed that decision and renews its arguments again here.

Noble Solutions states that Oregon's direct access law limits the transition charges to the pool of generation investments that "were" incurred on the customer's behalf, "prior to" the customers' direct access election. Noble Solutions' recommendation is based on its assertion that after year five, the fixed generation assets are "frozen" and therefore should decline due to accumulated depreciation. Noble Solutions maintains that the opt-out charge should decline by 2.36 percent per year to account for accumulated depreciation for a closed pool of generation six to ten years after a permanent opt-out election.

PacifiCorp responds that we have repeatedly found that the prohibition of cost shifting requires that the company forecast its fixed generation costs for a full ten years and recover those costs through Schedule 200 (reflecting actual fixed generation costs in years one through five) and through the opt-out charge (reflecting forecasted fixed generation costs in years six through ten). PacifiCorp states there are many costs to operate and maintain existing generation assets that increase over time and offset the impact of accumulated depreciation, such as overhauls, capital expenditures for maintenance, and union labor contracts.

Staff believes this issue should be rejected because it was decided in the 2016 TAM.

b. Resolution

We decline Noble Solutions' recommendation that the Consumer Opt-Out Charge should decrease in years six through ten, and reaffirm our findings from the 2016 TAM.[32]

Based on the record, we find PacifiCorp's forecast of fixed generation costs to be reasonable. Essentially, PacifiCorp takes its fixed generation costs as of year one, escalates those costs at an inflationary rate to estimate years six through ten, factors in the costs or benefits of freed-up energy, and converts the resulting amount into an annual charge that is assessed during the departing customer's five-year opt-out period. PacifiCorp explains that the consumer opt-out charge includes other costs that escalate over time and more than offset the impact of accumulated depreciation. Thus, based on the record, the assumption that fixed generation costs increase at the rate of inflation is reasonable.

For the next TAM proceeding, we direct PacifiCorp to provide a historical time series of fixed generation costs broken down by its components (*e.g.*, capital, O&M) as a check on the reasonableness of its forecasts.

H. Next Steps

In this and prior TAM proceedings, Staff and the intervenors have expressed continuing concerns about the complexity of PacifiCorp's GRID model and external adjustments. We acknowledge these concerns about the complexity of PacifiCorp's modeling, which are compounded by the compressed annual schedule we use to review PacifiCorp's TAM filings. At the same time, we recognize that the GRID model is complex because PacifiCorp's system is, in fact, a complex system to model. Because power costs are a key component of utility rates, we expect

[32] Order No. 15-394 at 12 ("PacifiCorp explains that incremental generation is not added after year five. PacifiCorp also explains that, in real (inflation-adjusted) terms, the fixed generation costs are held constant through year 10. As we did in previous orders, we find it reasonable to assume that fixed generation costs will increase at the rate of inflation after year five."). This issue is pending appeal before the Oregon Court of Appeals.

PacifiCorp to update its prospective power costs using a high degree of technical analysis. We would likely criticize the company for any effort to update these costs using a less sophisticated, more simplistic methodology.

Although our primary concern is that the GRID model produces accurate results, we also aim to ensure that PacifiCorp's power cost modeling is as transparent as possible and, to the extent possible, verifiable by the Commission and the parties. To help address that concern, we direct PacifiCorp, Staff, and the parties to meet informally to address three GRID issues discussed in the introduction of this order.

IV. ORDER

IT IS ORDERED that:

1. Advice No. 16-05 is permanently suspended.

2. PacifiCorp, dba Pacific Power, shall update its net power costs to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism NPC for calendar year 2017 and file its tariffs to be effective January 1, 2017.

3. PacifiCorp, dba Pacific Power, shall delay filing of its long-term fuel supply plan for the Jim Bridger coal plant. We direct PacifiCorp, Staff of the Oregon Public Utility Commission and the parties to informally meet and discuss (1) the information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for the Jim Bridger coal units in future Transition Adjustment Mechanism (TAM) proceedings, as well as (2) whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal-fired units, as discussed in the body of this order. We direct Staff to report back to us on the results of those discussions, with any recommendations, at our January 24, 2017 Public Meeting.

4. We direct PacifiCorp, dba Pacific Power, Staff of the Oregon Public Utility Commission, and the parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) REC valuation, as discussed in the body of this order. Staff shall report back to us on the results of those discussions before PacifiCorp's 2018 TAM is filed.

5. For the next TAM filing, we direct PacifiCorp, dba Pacific Power, to include a historical time series of fixed generation costs included in its direct access opt-out charge, broken down by its components (e.g., capital, O&M) as a check on the reasonableness of its forecasts.

Made, entered, and effective DEC 20 2016.

Lisa D. Hardie
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1312

Docket No. UE 390 Staff/700
Opening Testimony of Rose Anderson (redacted version)

September 1, 2023

CASE: UE 390
WITNESS: Rose Anderson

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 700

Opening Testimony

June 09, 2021

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Senior Economist employed in the Energy Resource Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's analysis of the Economic Coal Cycling Study and the economics of PacifiCorp's recent coal contract minimum take levels.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to Exhibit Staff/701, I prepared Exhibit Staff/702 (PacifiCorp's responses to Data Requests) and Exhibit Staff/703 (PacifiCorp's confidential responses to Data Requests).

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, ECONOMIC COAL CYCLING STUDY

Q. Please provide a background on PacifiCorp's Economic Coal Cycling Study (Coal Cycling Study or Study.)

A. In the Stipulation in Docket No. UE 375 (2021 TAM), PacifiCorp agreed to provide a study on "the costs and benefits of economic cycling including the non-fuel cost impacts by March 1, 2021."[1] In Opening Testimony PacifiCorp reports that it sent a copy of its completed Study to parties to the 2021 TAM.[2] PacifiCorp has also included a copy of its Coal Cycling Study as an attachment to the testimony of David G. Webb.[3]

Q. Please summarize the Coal Cycling Study.

A. The Coal Cycling Study is based on a GRID model run using the input data from the 2021 TAM. In the Study, "must run" assumptions for all of the Company's coal plants have been turned off, allowing the coal units to cycle off whenever GRID expects that their operation would be uneconomic. The study finds that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** However, PacifiCorp reports that the generation plan resulting from this model run could not be reliably used to serve load, since it includes an unrealistic number of emergency purchases.[4]

[1] UE 375 - Stipulation at 8.
[2] PAC/100, Webb/14.
[3] PAC/107.
[4] PAC/100, Webb/14.

Emergency Purchases in GRID, PacifiCorp explains, "are the result of modeling resource shortages and occur when resources in an area of the Company's system are fully dispatched, and / or transmission into the area is insufficient to meet the load in that area."[5] In Opening Testimony, PacifiCorp reports that, in the Coal Cycling Study, "Since emergency purchases are not actual transactions available to the Company, the modeling result reflected a solution that did not reflect actual operations and could not reliably serve load."[6]

Q. What is Staff's reaction to the Coal Cycling Study?

A. Staff would like to share two reactions to the Study. First, Staff appreciates the Company's work on the Study and considers it a step toward determining whether PacifiCorp could reduce power costs for customers by cycling its coal plants. However, the study is inadequate for identifying whether economic cycling at one or more coal units may be able to create savings for customers through the reduction of annual net power costs. PacifiCorp has a responsibility to its customers to look further into this possibility. The results of the Study, along with the generally unfavorable market environment for coal generation, indicate that cycling one or more coal unit(s) off **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** may prove to be a reasonable course of action.

[5] Staff/702, Anderson/1. (PacifiCorp's response to Staff DR 61).
[6] PAC/100, Webb/14.

Second, Staff has an unresolved question regarding the quantity of emergency purchases in the Study, as compared to the 2022 TAM. Staff's understanding of the Coal Cycling Study is that it turned off "must run" assumptions for coal units and kept all other assumptions the same as in the 2021 TAM. The result was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as compared to the 2021 TAM. [7] However, in the 2022 TAM, making the same adjustment by turning off the "must run" setting has apparently only resulted **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in emergency purchases as compared to the counterfactual study with "must run" turned on.[8,9] Staff is uncertain why the change in emergency purchases resulting from turning off the "must run" setting would be so dramatically different in the 2022 TAM, as compared to the Economic Coal Cycling Study just one year earlier.

Staff's hypothesis is that the dramatic improvement in emergency purchases in the 2022 TAM may be a result of the changes in GRID assumptions made in the 2022 TAM and described in PacifiCorp's Opening Testimony.[10] If this hypothesis is correct, then the Company has already shown that the Economic Coal Cycling Study can easily be improved with a few modeling changes already implemented in the 2022 TAM.

[7] PAC/107, Webb/2.
[8] PAC/102, Webb/4.
[9] Staff/703. PacifiCorp workpaper "SL02 ORTAM22_xCoal Cycling CONF"
[10] PAC/100, Webb/15-16.

Q. What is Staff's recommendation regarding economic cycling moving forward?

A. PacifiCorp should perform a follow-up study that seeks to identify potential cost savings from economic coal cycling as part of a reliable generation plan.

Q. Why is a follow-up study warranted?

A. While Staff appreciates the modeling performed by the Company in this initial Study, it is not a full and rigorous treatment of economic cycling opportunities. A follow-up Economic Cycling Study is essential to understanding whether economic cycling at one or more additional coal units is a reasonable way to create savings for customers. The existing Coal Cycling Study does not provide an answer to this important question.

Q. Do you have a specific recommendation regarding the future modeling?

A. Yes. The Coal Cycling Study allowed any coal unit to cycle off at any time, resulting in an unreasonably high amount of emergency purchases in GRID.[11] A next step toward identifying economic cycling opportunities should be to look into economic cycling in a way that meets the requirements of a reliable generation plan. This could be done by reducing the number of coal units that are allowed to cycle off at a given time, by looking for available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, and/or by utilizing a new model that is able to consider reliability in its economic cycling decisions. PacifiCorp's reply to

[11] PAC/100, Webb/14.

Staff DR 165 indicates that the AURORA model may be able to consider reliability when economically cycling units.[12]

Q. What if this model is not capable of identifying units for economic cycling?

A. If PacifiCorp cannot find a model capable of considering reliability while identifying which coal units to cycle, then PacifiCorp could reduce the number of plants that are considered for cycling off at any given time. PacifiCorp could evaluate economic cycling only for the unit(s) or plant(s) that are expected to provide the least value to the system during shoulder months. Value to the system could be estimated by considering multiple factors including ramp rate, total ramping ability in MW, variable operating costs, ancillary services, and historical EIM revenues.

Q. Please summarize your recommendation.

A. PacifiCorp should perform a follow-up economic cycling study that seeks to identify additional opportunities for cost savings through economic coal cycling. Following the conclusion of the 2022 TAM, PacifiCorp should be required to both solicit feedback from Staff and other interested stakeholders and then complete a follow-up study prior to the next TAM.

[12] Staff/702, Anderson/2.

ISSUE 2: MINIMUM TAKE LEVELS IN PACIFICORP'S NPC FORECAST

Q. In the final Order in the 2021 TAM, the Commission requested that parties discuss whether minimum take levels should be included in power cost modeling, or should be removed to allow coal plants to generate at levels more consistent with market dynamics. What is Staff's position regarding modeling of minimum take levels in power cost dockets?

A. Generally speaking, minimum take levels are creatures of contract, and therefore, should be reflected in rates to the extent that the contract itself is prudent. If a minimum take contract provision in a coal supply agreement is not prudent, then Staff finds that it would be appropriate to remove that minimum take level from power cost modeling as one possible remedy to the Company's imprudence for entering into the contract. However, in general, minimum take levels are actual constraints that the Company faces, and if they were prudently agreed to, they should be included in power cost modeling.

Staff does not advocate for exclusion of most historical coal contract minimum take levels in PacifiCorp's NPC forecast at this time, with the exception of the Huntington contract and some of the new coal contracts.

As discussed further below, my testimony recommends removing minimum take assumptions from the coal modeling associated with three of the five new coal contracts in the 2022 TAM,[13] as well as the most recent Huntington

[13] A total of five coal contracts are included for review for the first time in this TAM for coal supply to Dave Johnston, Hunter and Craig.

contract,[14] based on the Company's failure to demonstrate that it appropriately analyzed minimum take levels when determining whether and to what extent to enter into coal supply agreements with minimum take provisions.

[14] The Huntington coal contract was introduced by the Company in UM 1712, although the Commission declined to consider the reasonableness of the contract in that proceeding.

<u>ISSUE 3: MINIMUM TAKE PROVISIONS IN PACIFICORP'S COAL CONTRACTS</u>

Q. Please explain what a minimum take requirement is.

A. A minimum take requirement, or 'take or pay' agreement, is a contractual agreement to purchase a certain amount of coal or else pay full price for the coal, even if it's not delivered.[15] These agreements change the economics of coal generation by setting the incremental cost of coal burned at zero until the minimum take level is reached.[16] This is because a specific quantity of coal is effectively paid for ahead of time, before the Company knows whether it will be needed for generation. In PacifiCorp's Opening Testimony, the Company states that nearly all coal contracts include minimum take requirements because without them, a coal supplier would be required to make a large investment with no assurance that it would sell any coal.[17]

Another interesting quality of the take or pay agreements in PacifiCorp's recent contracts at Dave Johnston, Hunter, Craig, and Huntington is that they **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[15] Staff/702, Anderson/3. (PacifiCorp's response to Sierra Club DR 1.5).
[16] Ibid.
[17] PAC/200, Ralston/6.

[redacted][18] **[END HIGHLY CONFIDENTIAL]**

Q. How has PacifiCorp modeled minimum take requirements in GRID?

A. When a unit fails to generate at or above its minimum take level in the initial GRID run, PacifiCorp has explained that it must adjust the coal cost input downward at that unit and iteratively re-run the model until the model selects generation levels consistent with minimum take levels.[19] For example, this iterative adjustment process was required to bring generation levels for Colstrip, Hayden, and Huntington up to minimum take levels in the 2022 TAM modeling.[20]

Q. Please describe how PacifiCorp determined minimum take levels in its new coal contracts and the Huntington coal supply agreement.

A. PacifiCorp has explained in its Opening Testimony, and in subsequent discovery responses, that its coal contract negotiations around minimum take levels are informed by generation forecasts that are "part of the overall fueling budget for the company."[21] Additionally, the Company has explained that, before it is used in contract negotiations, this fueling budget forecast is 'reviewed for reasonableness' by comparing it to 'expected targets' which are

[18] Staff was able to review the coal contracts but not to make copies or take verbatim notes.
[19] PAC/100, Webb/30.
[20] Staff/702, Anderson/5. (PacifiCorp's response to Staff DR 66).
[21] PAC/200, Ralston/5.

based on historical generation volumes, adjusted for “expected changes in load, anticipated system resources, renewables, and plant retirements.”[22,23]

Q. What are Staff’s concerns about PacifiCorp’s contract negotiations around minimum take levels?

A. After reviewing discovery responses from PacifiCorp, Staff is concerned because, although the business plan generation forecast looks 10 years into the future, the response to one of Staff’s data requests indicates that the generation forecasts used to support minimum take decisions at the new coal contracts do not look more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** years into the future.[24,25] Additionally, as discussed in my testimony below, the forecasts mostly appear not to adequately consider **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Staff has general concerns about the fueling budget generation forecast being used to support PacifiCorp’s coal contract negotiations. Staff is doubtful that the forecast as used to inform negotiations and the ‘review for reasonableness’ described by PacifiCorp are rigorous enough to determine the best minimum take level for a given unit over the entire duration of a coal contract.

[22] Staff/702, Anderson/6. (PacifiCorp’s response to Staff DR 71).
[23] Staff/702, Anderson/8. (PacifiCorp’s response to Staff DR 157).
[24] Staff/702, Anderson 6. (PacifiCorp’s response to Staff DR 71).
[25] Staff/703. (Attachments to PacifiCorp’s response to Staff DR 71).

Staff finds that, especially given the uncertain economics of coal, any modeling that informs contract negotiations needs to be performed with the sole intention of identifying the optimal generation levels for a plant over the expected contract term. The use of the fueling budget generation forecast does not seem to fit this purpose.

Q. What is Staff's recommendation regarding the coal generation forecasts used to inform coal contract negotiations?

A. In order to show that any minimum take levels included in a coal supply agreement are prudent, PacifiCorp must show that it has thoroughly evaluated the most economic levels of coal generation, including economic cycling possibilities, prior to and while engaging in coal contract negotiations around minimum take levels. This prevents ratepayers from incurring costs unnecessarily when PacifiCorp's minimum take provisions cause its coal units to dispatch at times that would otherwise be uneconomic. Therefore, if PacifiCorp cannot demonstrate during the 2022 TAM that its forecasts meet the following requirements, the Company should make improvements to its generation forecast used to inform coal contract negotiations.

The forecast used to inform negotiations should:

1. Cover the entire duration of a coal contract,
2. Include the resource buildout from the Company's most recent Integrated Resource Plan, and
3. Consider opportunities to create savings for customers by cycling coal units or plants off during the off-peak season. This could be done by

including the results of a recent economic cycling study into the forecast, or by creating the forecast in a model that can effectively consider economic cycling.

Prior to designing an updated forecasting methodology, PacifiCorp should participate in discussion(s) with Staff and stakeholders and accept suggestions for implementing the improvements.

After developing a forecasting methodology with these improvements, and before the filing of the next TAM, the Company should provide a stakeholder workshop explaining in detail how the forecasting methodology has been improved. Finally, the next TAM filing should provide a summary of this process and the improved methodology.

DAVE JOHNSTON, HUNTER, AND CRAIG COAL CONTRACTS

Q. What are the new coal contracts included in this TAM?

A. PacifiCorp has included in the 2022 TAM a total of five new coal supply agreements for its Dave Johnston, Hunter, and Craig plants. A more detailed summary of these contracts can be found in PacifiCorp's Opening Testimony, and in the testimony of Staff Witness Mr. John Fox (Staff/600, Issue 2).[26]

Q. What is Staff's position on the contract length and minimum take levels of these new contracts?

A. Generally speaking, Staff is supportive of limiting coal contract length. Shorter contract length provides flexibility for the operation of the coal units, and provides one way to reduce the risk of these contracts to customers.

Regarding minimum take levels, the analysis that informed these contract decisions generally suffers from the same problems identified by Staff above. Staff does not find evidence that PacifiCorp has engaged in a robust analysis seeking to identify economic generation levels for each of the plants for the duration of the coal contracts, and considered that forecast prior to and during negotiating the contracts, which include minimum take provisions. In fact, based on the Company's fueling budget generation forecast workbooks provided to Staff, forecasts that informed negotiations for several of the contracts do not appear to look **[BEGIN CONFIDENTIAL]** [redacted]

[26] PAC/200, Ralston/2-10.

[redacted].[27,28] **[END CONFIDENTIAL]**

The fueling budget generation forecast that PacifiCorp used to support its negotiations around the new coal contracts does not appear suited to the job of identifying optimal economic generation levels for the coal plants for years to come. This is unacceptable. The Company should be seeking to reduce power costs for customers with its minimum take agreements.

Further, upon review of the coal contracts, Staff noted that **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff is continuing to investigate this contract feature, and is concerned that it is not supported by the workpapers provided in recent discovery responses.

Q. What is your assessment of minimum take levels in the Dave Johnston contract?

A. PacifiCorp's Dave Johnston contract is a perfect example of Staff's concern regarding the Company's business plan fuel forecast. The Dave Johnston contracts are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but the forecast that informed this contract negotiation was apparently **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[27] Staff/702, Anderson/6. (PacifiCorp's response to Staff DR 71).
[28] Staff/703. (PacifiCorp's response to Staff DR 71, Attachment 1).

forecast.[29,30] This is not forward-looking enough to consider potential changes to market conditions and new resource buildout during the contract's full length, and there is no indication that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** were considered in the Dave Johnston forecast.

Q. What is your assessment of minimum take levels in the Hunter contract?

A. The analysis for the Hunter generation forecast appears to be somewhat more robust, utilizing a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** with additional sensitivities to inform the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** new contracts.[31,32] In addition, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Q. What is your assessment of minimum take levels in the Craig contract?

A. The new Craig coal contract is a five-year agreement, and once again PacifiCorp's negotiations appear to have been based on a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** forecast of generation.[33] Staff is also concerned that PacifiCorp agreed to a minimum take requirement at this plant at all, given that the Trapper mine is an "affiliate captive mine

[29] Staff/703. (PacifiCorp's response to Staff DR 71, Attachment 1).
[30] Staff/702, Anderson/9. (PacifiCorp's response to Sierra Club Data Request 1.13, part a).
[31] Staff/703. (PacifiCorp's response to Staff DR 71, Confidential Attachment 2).
[32] PAC/200, Ralston/7.
[33] Staff/703. (PacifiCorp's response to Staff DR 71, Confidential Attachment 1).

owned by three of the five Craig plant owners."[34] Staff requests the Company explain in Reply Testimony why it has agreed to be bound to a minimum take level at a mine where it is one of the owners, instead of agreeing to divide its share of costs over the tons of coal it actually needs in a given year.

Q. Was generation at any of the plants with new coal contracts iteratively adjusted to meet a minimum take requirement in the 2022 TAM?

A. No. Hunter, Craig, and Dave Johnston did not require iterative adjustments to meet minimum take requirements in the 2022 TAM, indicating that GRID dispatched them at or above 2022 minimum take levels based on economics. While this reassures Staff that the 2022 minimum take levels in these contracts were set somewhat appropriately for 2022, the minimum take levels could eventually become binding constraints.

Q. What is Staff's recommendation regarding the new coal contracts?

A. PacifiCorp has not demonstrated that the analysis informing its negotiations for these units was a robust attempt to identify the economic generation levels that would be optimal over the contract timeframe, **[BEGIN CONFIDENTIAL]** [redacted] [**END CONFIDENTIAL]**. Unless PacifiCorp can prove it has performed a robust analysis consistent with these expectations, Staff recommends the removal of the minimum take level assumptions for Dave Johnston and Craig as modeled in Oregon power cost filings moving forward.

[34] PAC/200, Ralston/22.

It may be that, in a future TAM proceeding following development of a more rigorous methodology for forecasting economic levels of generation at its coal units, the improved methodology could be used to set minimum take levels for Craig and Dave Johnston. Staff would evaluate the merits of this approach in a future proceeding, but notes that it would help reduce risk for the Company while providing ratepayers with the benefit of a more reasonable estimate of minimum take levels that should have been reflected in the coal supply agreements from the outset.

Staff is continuing to look into the Hunter forecast. Since it appears to be more robust and appropriate, Staff does not recommend an adjustment or modeling change for Hunter at this time.

Q. What is Staff's understanding of how the minimum take agreements can be removed for the purpose of power cost modeling in the future?

A. Essentially, PacifiCorp should 1) refrain from adding a minimum take assumption to the modeling for applicable plants, and 2) model the applicable plants as having variable fuel costs equal to the price of coal, exactly as it would model them if it had negotiated the new coal contracts at the current price with no minimum take agreements.

Q. Does this recommendation require a dollar adjustment in the 2022 TAM?

A. No. Because Dave Johnston and Craig did not require an iterative adjustment to meet minimum take levels in the 2022 TAM,[35] no dollar adjustment is required.

HUNTINGTON

Q. Please provide background on the Huntington coal contract.

A. The Huntington coal contract was initially brought to the Commission in Docket No. UM 1712, regarding the Deer Creek Mine closure. In its initial application, PacifiCorp requested the Commission find the Huntington contract to be prudent.[36] However the Commission declined to provide pre-approval, and made it clear that the contract was not included in its assessment of the benefits of the Deer Creek Mine closure:

> Accordingly, we take no action as to the reasonableness of the Huntington and Hunter plants' CSAs at this time, including the risks imposed by the take-or-pay provision. PacifiCorp may seek recovery of the fuel costs associated with the CSAs in future power cost proceedings.[37]

In the 2016 TAM, PacifiCorp mentioned the Huntington contract in Opening Testimony,[38] however the contract does not appear to have been discussed any further in that proceeding.

Q. What are Staff's concerns regarding the Huntington contract?

[35] Staff/702, Anderson/5. (PacifiCorp's response to Staff DR 66).
[36] PacifiCorp's Application for Approval of the Deer Creek Mine Transaction in Docket No. UM 1712.
[37] *In re PacifiCorp*, OPUC Docket No. UM 1712, Order No. 15-161 (May 27, 2015).
[38] UE 296 - PAC/300, Larsen/4.

A. The implications of failing to sufficiently assess generation levels are much more troubling with respect to the Huntington contract than to the new contracts, which are shorter in duration. The Huntington contract began approximately five years ago and will not expire until **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This makes the Huntington contract PacifiCorp's **[BEGIN CONFIDENTIAL]** [redacted][39,40] **[END CONFIDENTIAL]** Staff is concerned that this contract may have been informed by a short-sighted generation forecast, in the same way that the new contracts appear to have been. However, PacifiCorp's responses to Staff discovery on this matter show that the Company has not retained any of the workpapers for analysis performed before negotiating the Huntington contract.[41]

PacifiCorp bears the burden of proving that its Huntington contract minimum take levels were decided prudently, based on what PacifiCorp knew or should have known at the time the contract was executed. Until PacifiCorp can demonstrate that the minimum take was set prudently, Huntington minimum take levels should not be included in power cost modeling.

Q. What would have been included in a robust consideration of economic generation levels at Huntington?

A. In Staff's opinion, a robust analysis of economic generation levels at Huntington would have included a long-term generation forecast that

[39] Staff/703. (PacifiCorp's confidential response to Sierra Club DR 1.12).
[40] Staff/702, Anderson/14. (Sierra Club DR 1.12).
[41] Staff/702, Anderson/10. (PacifiCorp's response to Staff DR 154).

considered the long-term resource buildout in the Company's most recent Integrated Resource Plan. The forecast would have been designed for the purpose of determining the most economic generation levels at Huntington over the entire duration of the contract, and it would not have assumed any minimum take levels for Huntington after the expiration of its current contract. It would have considered the possibility of economic cycling or early retirement.

Q. Please explain how the minimum take level at Huntington is currently harming customers.

A. The Huntington plant already requires iterative adjustments in the 2022 TAM because GRID would not choose to dispatch the plant to its minimum take levels otherwise.[42] This is true in the as-filed case with "must run" requirements turned off **[BEGIN CONFIDENTIAL]** [redacted].[43] **[END CONFIDENTIAL]** Already, about five years after the contract was signed, PacifiCorp has to manually increase the dispatch level at Huntington so that the minimum take quantity of coal can be utilized. This indicates to Staff that the minimum take levels in the Huntington contract were not calibrated appropriately for the economic realities even a few years into the future.

Q. What does Staff recommend regarding the Huntington plant in Oregon power cost dockets?

[42] Staff/702, Anderson/5. (PacifiCorp's response to Staff DR 66).
[43] Staff/703. (PacifiCorp's response to Staff DR 163, attachment).

A. PacifiCorp has not demonstrated that its generation forecast used to select minimum take levels in its Huntington coal contract was well-suited for that purpose. For this reason, ratepayers should not bear the entire cost of the uneconomic dispatch at Huntington for the duration of the Huntington contract. Staff recommends removing the minimum take requirement at Huntington in future TAM proceedings for purposes of forecasting NPC unless the Company can prove that its analysis used to negotiate minimum take levels was prudent.

Alternatively, if the Company develops a robust forecasting methodology for future minimum take provisions in coal supply agreements, then it may be appropriate to use the forecasting methodology to set a new, prudently determined minimum take level at Huntington for TAM modeling purposes.

For the 2022 TAM, Staff recommends an adjustment that represents the value lost by customers who pay for excess coal generation at Huntington instead of purchasing power at market prices or using lower cost generation. This would be calculated as the quantity generated at Huntington in GRID before iterative adjustments (Q_1), minus the quantity after iterative adjustments (Q_2), times the difference between the average Low Load Hour (LLH) market price at Mid-C and Palo Verde during the off-peak season in the 2022 TAM (P_1) and the cost of coal at Huntington (P_2), or, $(Q_1 – Q_2) * (P_1 – P_2)$. This downward adjustment should approximate the value lost to customers due to the minimum take agreement at Huntington. Staff's preliminary calculation results in a dollar adjustment of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis. [44, 45, 46]

Alternatively, PacifiCorp could re-run the GRID model without minimum take assumptions at Huntington and the results could be used to make an adjustment.

Q. Is it reasonable for the Commission to require a change to the modeling of the Huntington contract now, several years after it was signed and included in rates?

A. Yes. At the time that the Company executed the Huntington coal supply agreement, it was aware of concerns about minimum take provisions in coal contracts and the impact on economics for the Company's coal generating units in the long-term.[47] Nevertheless, the Company executed the agreement. The Commission's prudence standard judges prudence based on what the Company knew or should have known at the time the decision was made.[48] While the Commission may have approved power costs with the full minimum take level at Huntington in the past, in this year's TAM it has become clear that there is little reason for confidence in the analysis used to support the minimum take level in the Huntington coal contract. The Company has been unwilling or unable to provide supporting evidence otherwise.

[44] Staff/702, Anderson/12. (PacifiCorp's response to Staff DR 162 provided Q_1 and Q_2).
[45] See PacifiCorp's 2020 FERC Form 1 for Huntington cost per MWh, accessed at https://apps.puc.state.or.us/edockets/docket.asp?DocketID=17653.
[46] This calculation used PAC's Average 2022 market prices at Palo Verde and Mid C during off-peak months as forecast in the 2022 TAM.
[47] Order No. 15-161 at 10-12.
[48] Order No 12-493 at 25-27.

Q. Does this conclude your testimony?

A. Yes.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1313

Docket No. UE 207
Order No. 09-432

September 1, 2023

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of PACIFICORP, dba PACIFIC POWER 2010 Transition Adjustment Mechanism	ORDER

DISPOSITION: STIPULATION ADOPTED

I. BACKGROUND

On March 30, 2009, PacifiCorp, dba Pacific Power (Pacific Power or the Company), filed revised tariff sheets for Schedule 200, as well as testimony and exhibits regarding the Company's 2010 Transition Adjustment Mechanism (TAM), with the Public Utility Commission of Oregon (Commission). Pursuant to Order No. 05-1050, Pacific Power is required to make an annual TAM filing by April 1 of each year. The purpose of the TAM filing is to update the Company's annual net power costs (NPC) and to set transition credits for Oregon customers choosing direct access. Pacific Power requested an effective date of January 1, 2010, for the Schedule 200 revised tariff sheets.

The 2010 TAM filing, as initially submitted on March 30, 2009 (Initial Filing), reflected a forecasted, normalized NPC for the test period (12 months ending December 31, 2010) of approximately $1.101 billion on a system-wide basis (total-Company NPC), and $273 million on an Oregon-allocated basis (Oregon NPC). The latter amount is approximately $20.6 million greater than the NPC baseline established in the 2009 TAM (docket UE 199), as adjusted for forecasted load loss in 2010, resulting in a 2.1 percent overall increase in Oregon rates.

On July 14, 2009, reply testimony was filed by Commission Staff (Staff), the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board (CUB), and Sempra Energy Solutions, LLC (Sempra). On August 11, 2009, Pacific Power filed rebuttal testimony and exhibits. On August 25. 2009, surrebuttal testimony was filed by Staff, ICNU, and CUB. On September 4, 2009, Pacific Power filed sur-surrebuttal testimony and exhibits.

As part of the Company's rebuttal testimony filed on August 11, 2009, Pacific Power filed an update and corrections to the Initial Filing (Rebuttal Update). The Rebuttal Update decreased the Company's forecasted normalized 2010 NPC on an Oregon-allocated basis, as filed in the Initial Filing, by $0.6 million to $272.4 million.

Settlement conferences were held on August 18, 2009, and September 10, 2009. Pacific Power, Staff, ICNU, CUB, and Sempra participated in both settlement conferences.

On September 11, 2009, Pacific Power notified the Commission that a comprehensive settlement in principle on all 2010 TAM issues had been reached among Pacific Power, Staff, CUB, ICNU, and Sempra. On September 25, 2009, Pacific Power filed the executed Stipulation along with Joint Testimony in Support of the Stipulation.

II. THE STIPULATION AND SUPPORT FOR THE STIPULATION

The Stipulation, attached to this order as Appendix A, provides that Pacific Power, Staff, CUB, ICNU, and Sempra (the Stipulating Parties) agree, subject to the final TAM update (Final Update), to a baseline 2010 TAM NPC in rates and an increase in NPC revenues to be collected in 2010. The Stipulating Parties further agree on TAM guideline issues raised in two dockets, UE 207 and UE 210.

A. 2010 NPC

The Stipulating Parties agree that Pacific Power's total-Company NPC for 2010 will be $1.031 billion, subject to the Final Update.

The Stipulating Parties agree that the total-Company NPC of $1.031 billion results in an Oregon NPC of $256,395,751, thereby increasing Oregon rates by $4 million, or approximately 0.4 percent, as set forth in Exhibit A to Appendix A.

B. NPC Baseline and Updates

The Stipulating Parties agree that Pacific Power will revise the Rebuttal Update for the NPC elements twice, as prescribed by the TAM Guidelines. On November 9, 2009, Pacific Power will file the "Indicative Run," and on November 16, 2009, Pacific Power will file the "Final Update." Contracts will be "locked down" on November 2, 2009. Changes produced by the updates in November may be positive or negative and the Stipulating Parties agree that there is no cap on the updates to be made in November.

Exhibit B to Appendix A sets forth a baseline NPC report that reflects the stipulated total-Company NPC prior to either update. The report includes adjustments to specific NPC elements for purposes of calculating the total-company NPC and the Oregon NPC. All adjustments, except for Pacific Power's Condit facility, will be updated in November. For the Condit Facility, the Company will run the GRID model with a full year of forecast data, as the Stipulating Parties agree, rather than the nine months of forecast data and a proxy amount for the last three months of 2010 currently included in the NPC report. The Stipulating Parties agree that the adjustments reflected in this report are for settlement purposes only and do not imply agreement on the merits of the adjustments, nor acceptance of any NPC elements. Pacific Power agrees to provide workpapers with each update in November. The workpapers will track the incremental and cumulative changes to the estimated NPC for 2010.

C. UM 1355

The Stipulating Parties agree that the Commission's order in docket UM 1355 will not affect the projected $4.0 million increase in NPC for 2010 and that such notice will be filed in that docket. The Stipulating Parties further agree that Pacific Power will implement any specific orders made by the Commission in docket UM 1355 in the Company's next TAM filing or general rate case filing.

D. Accounting Application

Pacific Power agrees to request, concurrent with the filing of this Stipulation, permission to withdraw, without prejudice, the Company's application for an accounting order regarding Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) No. 04-6 (relating to coal stripping costs) in docket UM 1448. The Stipulating Parties agree not to oppose such a request.

E. TAM Guidelines

The Stipulating Parties agree to interpret or amend certain TAM Guidelines for this and all future proceedings.[1] The parties indicate that "a difference came to light" during this proceeding "between how the Company and other parties interpret the TAM Guidelines in terms of limitations on other parties."[2] The Stipulating Parties agree to language in the Stipulation that explains how the TAM Guidelines should be interpreted to apply in a more "symmetrical manner with respect to specific issues concerning inputs, costs, updates, modeling assumptions, methodologies and error corrections."[3] The Stipulating Parties agree that: (1) the TAM Guidelines define the types of errors and omissions that the Company can correct after the Initial Filing but do not limit the ability of parties, including the Company, to propose corrections consistent with TAM Guidelines after the Company's Initial Filing; (2) the TAM Guidelines define the scope of the updates that the Company can make to its GRID model after the Initial filing but do not limit the ability of other parties to propose updates consistent with the TAM Guidelines after the Company's Initial Filing; and (3) the TAM Guidelines define the cost elements that will be included in the Company's NPC in stand-alone TAM proceedings, but do not limit the ability of parties, including the Company, to propose changes to the TAM Guidelines, including changes to the cost elements that will comprise NPC in stand-alone TAM proceedings, in future rate cases.

Issues regarding the interpretation and application of TAM Guidelines were also raised in docket UE 210. The Stipulating Parties (which include all parties to docket UE 210 as well) agreed, however, to address the two TAM Guideline issues that are outstanding in docket UE 210 in this docket:

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[1] The TAM Guidelines, originally adopted by the Commission in Order No. 09-274, describe the general purpose and scope of TAM proceedings, delineate workpapers and supporting documents that Pacific Power must provide with TAM filings, and provide guidance on timing and elements of different filings in TAM proceedings. At the time the TAM Guidelines were adopted, it was acknowledged that not all potential issues regarding the process and scope of the TAM had been resolved. Order No. 09-274 at 6.
[2] Joint Testimony at 8.
[3] *Id.*

1. New Generation Resources without Fixed Cost Recovery

At issue was the question of, "whether variable costs of a new generation resource could be included in a stand-alone TAM if the Company will not recover the fixed costs in the TAM rate effective period?"[4] The Stipulating Parties agree to amend the TAM Guideline that addresses when the variable costs and dispatch benefits of new resources will be included in stand-alone TAM filings. The TAM will include the variable costs and dispatch benefits of new resources that are not eligible for recovery through the Renewable Adjustment Clause (adopted in Order No. 08-548) if: (a) the Company has acquired the resource prior to April 1 of the year of the stand-alone TAM filing; or (b) the Company built the resource, and it was used and useful prior to April 1 of the year of the stand-alone TAM filing.

The prudence of building or acquiring the resource will be determined in the stand-alone TAM proceeding. Parties are not prohibited from challenging the prudence of the Company's decision or proposing a disallowance of related costs. Notice will be provided by March 1 of the year of a stand-alone TAM filing that the filing will include a new resource that falls under this guideline.

2. Methodological Changes

Another question asked whether "changes in methodologies utilized in the calculation of NPC will be permitted in stand-alone TAM proceedings."[5] The Stipulating Parties agree to modify TAM Guidelines to permit Pacific Power to propose changes to the methodologies used to calculate the cost elements and other inputs to the GRID model in stand-alone TAM filings. The Company will provide notice of substantial changes to the logical constructs, methodologies, or calculations used in the GRID model by March 1 of the year of a stand-alone TAM filing. Pacific Power also agrees to explain and justify any substantial change in model logic, methodology, or calculation in the Company's annual TAM filing on April 1. For each such change, the Company will provide, when practical to do so, workpapers that contain a side-by-side comparison of GRID model results with and without the proposed change. The Stipulating Parties agree that methodological changes or challenges to the Company's existing or proposed methodologies may be addressed in future general rate cases or stand-alone TAM filings.

F. Calculation of Transition Adjustments.

Transitions Adjustments in Schedules 294 and 295 will be calculated based on the Final Update. The Transition Adjustments in Schedules 294 and 295 will also be consistent with the modifications to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order No. 08-543 in docket UE 199.[6]

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[4] Joint Testimony in Support of Stipulation at 6.
[5] *Id* at 7.
[6] The Stipulating Parties explain at 11 of the Joint Testimony:

Section 15 of the docket UE 199 Stipulation modifies the calculation of the transition adjustment in two ways: (1) the Company will relax the market cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB to determine the value of the freed up power; and (2) any remaining monthly thermal

For purposes of calculating the Transition Adjustments in Schedules 294 and 295, the Stipulating Parties agree that losses will include primary and secondary line losses, as applicable, in addition to the transmission losses already included in the calculation.

As the Stipulating Parties agree that direct access customers may no longer bypass Schedule 200, it will not be subtracted in the calculation of the Transition Adjustment Schedules 294 and 295 for all months in 2010. To implement this change effective on January 1, 2010, Pacific Power will file revised tariff sheets for Schedule 200 with per kilowatt-hour rates for direct access rate schedules that collect the portion of Schedule 200 that may no longer be bypassed. Direct access customers will pay the rate that is comparable to the proposed Schedule 200 in docket UE 210.

G. Multi-Year Opt Out Enrollment Period

The Stipulating Parties agree that the enrollment period for the Multi-Year Opt-Out Schedule 295 will be extended, beginning at Noon on November 16, 2009, and ending at Noon on December 7, 2009.

H. Revenue Allocation and Rate Design

The Stipulating Parties agree that the final Oregon-allocated NPC increase and load change adjustment will be calculated according to TAM Guidelines and as illustrated in Exhibit C to Appendix A.

Pursuant to TAM Guidelines and a Stipulation filed in docket UE 210, the Stipulating Parties propose to change the current rate design for Schedule 200. As proposed, all NPC would be collected through a new Schedule 201, Net Power Costs, which will be a rider to Schedule 200. Schedule 200 would collect all other generation costs. To implement the change should the Stipulation in docket UE 210 be approved, the Company will file the redesigned schedules in a compliance filing in that docket, to be effective February 2, 2010.

I. Tariffs

The Stipulating Parties agree that Pacific Power will file, concurrent with the filing of the Final Update, revised Schedule 200 rates as well as revised Schedules 294 and 295 (Transition Adjustment) as a compliance filing in docket UE 207. These revised tariffs will be consistent with the Stipulation in this docket and will be effective as of January 1, 2010. For the period of January 1, 2010, through February 1, 2010, the final NPC revenue increase will be spread by Schedule 200 alone. After February 1, 2010, the NPC rates will be collected pursuant to the new Schedule 201, if approved.

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generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. The monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanism will remain in effect.

III. DISCUSSION

The Commission encourages Staff and parties to voluntarily resolve issues to the extent that settlement is in the public interest. Staff and all parties entered into a Stipulation that resolves all primary issues in this proceeding. No person has filed an objection to the Stipulation.

The Commission has examined the Stipulation, the Joint Explanatory Brief, and the pertinent record in the case. The Commission concludes that the Stipulation is an appropriate resolution of all primary issues in this docket. The Commission adopts the Stipulation in its entirety without modification.

The Commission notes, however, that certain methodological modeling matters raised merit additional analysis in future TAM filings. For example, the Commission expects Staff and parties to continue to evaluate and address in Pacific Power's next TAM issues regarding how to best model Pacific Power's hydro and thermal generation, and the question of whether other revenue associated with variable power costs should be updated in a stand-alone TAM filing. The Commission also expects Pacific Power to keep it apprised of the status of the Federal Energy Regulatory Commission (FERC) study on wind integration and its potential impact on Oregon customers. Pacific Power should notify the Commission when it determines whether or not to include a wind integration tariff in the Company's next FERC rate case.

IV. ORDER

IT IS ORDERED that:

1. The Stipulation is adopted.

2. Consistent with the Stipulation, Pacific Power will file two Transition Adjustment Mechanism (TAM) Updates in November. On November 9, 2009, Pacific Power will file the Indicative Run, and on November 16, 2009, Pacific Power will file the Final Update.

3. Advice No. 09-007, filed by Pacific Power on March 30, 2009, is permanently suspended.

4. Pacific Power will file revised Schedules 200, 294, and 295 rates concurrent with the filing of the Final Update. These revised tariffs will be consistent with the Stipulation in this docket and will be effective as of January 1, 2010. For the period of January 1, 2010, through February 1, 2010, the final NPC revenue increase will be spread by Schedule 200 alone. After February 1, 2010 the NPC rates will be collected pursuant to the new Schedule 201, if approved.

5. Pacific Power will provide an update to the Commission in 2010 on the status of the Federal Energy Regulatory Commission (FERC) study on wind integration and its potential impact on Oregon customers. Pacific Power will also notify the Commission if the Company will include a wind integration tariff in the Company's next FERC rate case.

Made, entered, and effective OCT 30 2009.

Lee Beyer Chairman	**John Savage** Commissioner
	Ray Baum Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 207

In the Matter of: PACIFICORP, dba PACIFIC POWER 2010 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service	STIPULATION

This Stipulation is entered into for the purpose of resolving the issues among the parties to this Stipulation related to PacifiCorp's (or the "Company") proposed transition adjustment mechanism ("TAM") for direct access that updates the Company's net power costs ("NPC") in rates.

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Sempra Energy Solutions LLC ("Sempra") (together, the "Parties"). The Parties represent all participants and intervenors in this docket.

BACKGROUND

2. On March 30, 2009, PacifiCorp filed revised tariff sheets for Schedule 200, PacifiCorp's 2010 Transition Adjustment Mechanism, to be effective January 1, 2010. The purpose of the TAM filing is to update NPC for 2010 and to set transition adjustments for Oregon customers who choose direct access in the November 2009 open enrollment window.

3. The March 30, 2009 TAM filing ("Initial Filing") reflected total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2010) of approximately $1.101 billion. On an Oregon-allocated basis, the forecasted normalized NPC in the Initial Filing were approximately $273 million. This amount is approximately $20.6 million higher than the $252.4 million included in rates through the NPC baseline established

in the 2009 TAM (Docket UE 199), as adjusted for forecasted load loss in 2010. This would have resulted in an overall increase to Oregon rates of approximately 2.1 percent.

4. On August 11, 2009, the Company filed an update and corrections to the Initial Filing ("Rebuttal Update"). The updates and corrections decreased the Company's forecasted normalized NPC for the calendar year 2010 on an Oregon-allocated basis to $272.4 million. This reflected a decrease of $0.6 million from the Company's Initial Filing.

5. The Parties convened settlement conferences on August 18, 2009 and September 10, 2009. All Parties to the docket participated in the settlement conferences.

6. As a result of the settlement conferences, the Parties have reached a comprehensive settlement in this case. The settlement establishes the baseline 2010 TAM NPC in rates, subject to the final TAM updates; the increase in NPC revenues to be collected in 2010; and issues relating to the TAM Guidelines addressed in this docket and in Docket UE 210.

AGREEMENT

7. <u>2010 NPC.</u> The Parties agree that the total-Company NPC for 2010 will be $1.031 billion, subject to the Final Update described in Section 8. The Parties agree that the total-Company NPC of $1.031 billion results in Oregon-allocated NPC of $256,395,751, which is an increase of $4.0 million on an Oregon-allocated basis over the $252,395,751 that would be collected by current rates, as shown in Exhibit A. This results in an overall increase to Oregon rates of $4 million, or approximately 0.4 percent.

8. <u>NPC Baseline and Final Update.</u> The Company will update its Rebuttal Update for the NPC elements described in the TAM Guidelines, adopted by the Commission in Order No. 09-274, on November 9, 2009 (the "Indicative Run") and November 16, 2009 (the "Final Update"), with a contract lock-down date of November 2, 2009. Exhibit B to the Stipulation is the baseline net power cost report that reflects the stipulated total company NPC, prior to the November updates described in this Section. The Parties agree that the adjustments

reflected in the baseline net power cost report are for settlement purposes only and do not imply agreement on the merits of the adjustments, nor do they imply that the Parties have accepted any elements of the Company's NPC study. With each of the two GRID model updates listed above, the Company will provide workpapers that track the incremental and cumulative changes to the estimated NPC for 2010 from this baseline. This tracking will provide a step-by-step progression of each change to the GRID model and its incremental impact on forecasted NPC for 2010. Nothing in this paragraph is intended to change or override the workpaper and other filing requirements in place under the TAM Guidelines for the final updates.

9. UM 1355. The $4.0 million increase described in Section 7 includes any changes to NPC for 2010 that may result from the Commission's decision in Docket UM 1355. The Commission's order in Docket UM 1355 will not affect the $4.0 million increase. The Parties agree to file notice in Docket UM 1355 that the parties have resolved the potential revenue impact from that docket on the 2010 TAM through this Stipulation. The Parties further agree that the Company will implement the Commission's decision in Docket UM 1355 in its next TAM filing and/or general rate case filing.

10. EITF Accounting Application. PacifiCorp agrees that it will request concurrently with the filing of this Stipulation that the Commission permit it to withdraw without prejudice its application for an accounting order regarding EITF 04-6, now docketed in UM 1448. The Parties agree to not oppose PacifiCorp's request to withdraw its application for an accounting order regarding EITF 04-6.

11. TAM Guidelines. The Parties agree that in this and future TAM filings, the TAM Guidelines will be interpreted or amended to include the following new or clarifying provisions in sections 12-14 of this Stipulation. The Parties agree to file notice in Docket UE 210 that the Parties have resolved the TAM design-related issues in that docket through this Stipulation.

12. New Generation Resources without Fixed Cost Recovery. The Company will include the variable costs and dispatch benefits of new resources that are not eligible for inclusion in the Renewable Adjustment Clause in its NPC in stand-alone TAM proceedings, irrespective of whether the fixed capital costs of the new resource are already included in rates, if: (a) the Company acquired the resource prior to April 1st of the year of the stand-alone TAM filing, or (b) the Company built the resource and it was used and useful prior to April 1st of the year of the stand-alone TAM filing.

The prudence of the decision to build or acquire the resource will be determined in the stand-alone TAM proceeding prior to including the variable costs and dispatch benefits in rates. This provision does not limit the Parties' ability to challenge the prudence of the Company's decision to build or acquire the resource in subsequent rate proceedings based on the discovery of new information or evidence, to the extent provided by law. This provision also does not limit the Parties' ability to propose a disallowance of the fixed capital costs or fixed construction costs associated with the new resource in subsequent rate proceedings. The Company will provide notice to the parties if a new resource subject to this section will be included in the TAM filing by March 1st of the year of the stand-alone TAM filing.

13. Methodological Changes. The Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the GRID model or to the logic of the GRID model by March 1st of the year of a stand-alone TAM filing. The Company will include in its April 1st TAM filing a justification for each substantial change in methodology, calculation of cost elements, or model logic. For each change in input methodology or model logic, where practical, the Company will also provide workpapers that contain a side-by-side comparison of GRID model results with and without the proposed change in methodology, calculation of cost elements or model logic. The Parties agree that methodological changes, or challenges to the Company's existing or proposed methodologies

can be addressed in future stand-alone TAM proceedings, whether litigated in a general rate case or a stand-alone TAM filing.

14. Clarification/Revision of TAM Guidelines.

a. The TAM Guidelines, established in Order No. 09-274, define the types of errors and omissions that the Company can correct after its Initial Filing. The Parties agree that the TAM Guidelines do not limit the ability of Parties, including the Company, to propose corrections consistent with the TAM Guidelines after the Company's Initial Filing.

b. The TAM Guidelines, established in Order No. 09-274, define the scope of the updates that the Company can make to its GRID model after its Initial Filing. The Parties agree that the TAM Guidelines do not limit the ability of other Parties to propose updates consistent with the TAM Guidelines after the Company's Initial Filing.

c. The TAM Guidelines, established in Order No. 09-274, define the cost elements that will be included in the Company's NPC in stand-alone TAM proceedings. The Parties agree that the TAM Guidelines do not limit the ability of the Company or other Parties to propose changes to the TAM Guidelines, including changes to the cost elements that will comprise NPC in stand-alone TAM proceedings, in future general rate cases.

15. Transition Adjustments.

a. Transition adjustments in Schedules 294 and 295 will be calculated based on the Final Update and consistent with the modifications to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order No. 08-543 in Docket UE 199.

b. For consistency, the Transition Adjustment for all months in 2010 shall reflect the Parties' agreement that, with the implementation of changes to Schedules 200 and 201 in UE 210, Schedule 200 will no longer be bypassable to direct access customers and will not be subtracted in the calculation of the Transition Adjustment. For January 2010, the Company will calculate the rate that is comparable to the proposed Schedule 201 in UE 210, and direct access customers will pay the rate that is comparable to the proposed Schedule 200 in UE 210.

c. For purposes of calculating the transition adjustments in Schedules 294 and 295, losses will include primary and secondary line losses, as applicable, in addition to the transmission losses already included in the calculation.

16. Multi-Year Opt Out Enrollment Period. The Parties agree that the enrollment period for the Multi-Year Opt Out (Schedule 295) will begin at Noon on November 16, 2009 and end at Noon on December 7, 2009.

17. Revenue Allocation and Rate Design. The Parties agree that the final Oregon-allocated NPC increase and load change adjustment will be calculated consistently with the TAM Guidelines and as illustrated in Exhibit C.

18. Tariff. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 200 rates and revised transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 207, effective January 1, 2010, reflecting rates designed as agreed in this Stipulation.

19. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the adjustments and the rates resulting from their application are sufficient, fair, just, and reasonable.

20. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and any appeal, (if necessary) provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

21. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material

conditions in approving this Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

22. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

23. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such Party's signature.

PACIFICORP

By: Andrea Kelly

Date:

STAFF

By:

Date:

CUB

By:

Date:

ICNU

By:

Date:

SEMPRA

By:

Date:

PACIFICORP

By: ____________________

Date: ____________________

STAFF

By: ____________________

Date: 9/25/9

CUB

By: ____________________

Date: ____________________

ICNU

By: ____________________

Date: ____________________

SEMPRA

By: ____________________

Date: ____________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: [signature]

Date: 9-25-09

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: [signature]

Date: Sept 25 2009

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP	**STAFF**
By: __________	By: __________
Date: __________	Date: __________
CUB	**ICNU**
By: __________	By: __________
Date: __________	Date: __________

SEMPRA

By: Peter J. Richardson

Date: 9/25/09

Peter Richardson

Docket UE 207

STIPULATION OF JOINT PARTIES

Exhibit A

NPC Allocation

September 25, 2009

Exhibit A - NPC (UE 207)
Settlement - September 2009

	ACCOUNT	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010	Settlement Adjustment CY2010	Settlement CY2010		FINAL UE-199 CY 2009	FILED CY2010	GRC Reply Factors CY2010	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010	Settlement CY2010
Sales for Resale														
Existing Firm PPL	447	24,281,555	24,858,916	24,975,068	-	24,975,068	SG	26.411%	26.877%	26.877%	6,413,106	6,627,011	6,712,520	6,712,520
Existing Firm UPL	447	26,490,590	25,490,589	25,490,589	-	25,490,589	SG	26.411%	26.877%	26.877%	6,732,420	6,851,078	6,851,078	6,851,076
Post-Merger Firm	447	882,169,664	698,790,188	639,656,892	(4,392,436)	635,264,457	SG	26.411%	26.877%	26.877%	232,993,623	187,275,491	171,919,842	170,739,292
Non-Firm	447	-	-	-	55,979,012	55,979,012	SE	25.525%	25.002%	25.002%	-	-	-	13,995,616
Total Sales for Resale		931,941,809	748,937,693	690,122,550	51,586,576	741,709,126					246,139,168	200,753,578	185,483,438	198,298,704
Purchased Power														
Existing Firm Demand PPL	555	82,711,383	57,671,363	59,132,864	-	59,132,864	SG	26.411%	26.877%	26.877%	16,562,973	15,500,265	15,893,071	15,893,071
Existing Firm Demand UPL	555	46,726,726	47,195,846	46,584,477	-	46,584,477	SG	26.411%	26.877%	26.877%	12,341,196	12,684,773	12,520,456	12,520,456
Existing Firm Energy	555	66,847,124	55,596,693	58,930,634	-	58,930,634	SE	25.525%	25.002%	25.002%	17,062,588	13,900,229	14,733,777	14,733,777
Post-merger Firm	555	707,106,149	376,422,870	351,557,140	316,504	351,873,644	SG	26.411%	26.877%	26.877%	186,756,845	101,170,739	94,487,605	94,572,672
Secondary Purchases	555	-	-	-	(12,954,749)	(12,954,749)	SE	25.525%	25.002%	25.002%	-	-	-	(3,238,933)
Seasonal Contracts	556	7,886,490	-	-	-	-	SSGC	24.486%	0.000%	0.000%	1,882,756	-	-	
Other Generation Expense	655	5,247,631	11,022,399	7,682,475	-	7,682,475	SG	26.411%	26.877%	26.877%	1,385,048	2,962,477	2,064,810	2,064,810
Total Purchased Power		896,327,403	547,909,171	523,887,589	(12,638,244)	511,249,345					235,992,304	146,218,483	139,899,720	136,545,853
Wheeling Expense														
Existing Firm PPL	565	31,031,711	43,169,893	43,169,893	-	43,169,893	SG	26.411%	26.877%	26.877%	8,196,919	11,606,098	11,606,098	11,606,098
Existing Firm UPL	565	172,446	168,268	168,268	-	168,268	SG	26.411%	26.877%	26.877%	45,546	45,226	45,226	45,225
Post-merger Firm	565	83,334,742	96,107,739	100,936,303	-	100,936,303	SG	26.411%	26.877%	26.877%	22,009,897	25,830,756	27,128,633	27,128,633
Non-Firm	565	184,789	282,748	274,921	-	274,921	SE	25.525%	25.002%	25.002%	47,167	70,692	68,735	68,735
Total Wheeling Expense		114,723,691	139,748,649	144,569,385	-	144,569,385					30,298,629	37,554,781	38,850,691	38,850,591
Fuel Expense														
Fuel Consumed - Coal	501	568,678,213	604,154,096	610,654,307	-	610,654,307	SE	25.525%	25.002%	25.002%	145,153,389	151,049,995	152,675,171	152,675,171
Cholla / APS Exchange	501	57,517,846	54,964,906	55,207,439	-	55,207,439	SSECH	25.897%	25.405%	25.406%	14,895,507	13,963,675	14,027,268	14,027,268
Fuel Consumed - Gas	501	27,408,356	21,128,838	8,793,603	-	8,793,603	SE	25.525%	25.002%	25.002%	6,995,924	5,282,536	2,198,568	2,198,568
Natural Gas Consumed	547	374,611,293	458,583,217	426,442,274	-	426,442,274	SE	25.525%	25.002%	25.002%	95,659,762	114,654,611	106,618,665	106,618,665
Simple Cycle Combustion Turb	547	23,655,226	17,499,425	12,469,820	-	12,469,820	SSECT	24.286%	23.563%	23.288%	5,744,981	4,123,302	2,903,764	2,903,764
Steam from Other Sources	503	3,541,671	3,494,899	3,498,000	-	3,498,000	SE	25.525%	25.002%	25.002%	904,004	873,791	874,566	874,566
Total Fuel Expense		1,055,810,407	1,159,825,082	1,117,065,444	-	1,117,065,444					269,353,588	289,947,711	279,298,011	279,298,011
Net Power Cost		1,134,719,692	1,100,545,210	1,095,399,889	(64,224,820)	1,031,175,049					289,315,263	272,967,390	272,364,884	268,395,791
													24.864%	
NPC in Rates from UE-199		1,043,323,002									266,835,529			

6,131,867	5,520,355	(10,439,778)	Increase Absent Load Change

Oregon-allocated NPC Baseline in Rates from UE 199	$	266,835,529
2009 MWH (excluding Schedule 33)		14,026,969
$/MWH in Rates		19.02
2010 MWH (excluding Schedule 33)		13,267,901
2010 Recovery of NPC in Rates	$	252,395,751

20,571,846	19,959,131	4,000,889	Increase With Load Change

(16,571,046) Variance from Original Filing

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ORDER NO. 09-432

Docket UE 207

STIPULATION OF JOINT PARTIES

Exhibit B

NPC Baseline

September 25, 2009

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010

	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	12,010,268	1,000,814	984,930	1,012,151	996,213	1,002,313	985,430	1,022,631	1,011,434	990,484	1,009,832	993,456	1,020,579
BPA Wind	2,746,457	344,454	288,814	279,831	217,271	205,016	166,316	124,735	116,197	155,395	227,090	286,056	335,480
Hurricane Sale	985,499	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125
LADWP (IPP Layoff)	25,490,689	2,164,955	1,956,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
PSCO	32,536,056	2,706,760	2,468,509	2,676,610	2,613,730	2,676,610	2,635,664	2,837,461	2,637,461	2,743,673	2,711,705	2,770,195	2,837,461
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD	12,964,800	1,505,900	547,600	-	182,600	-	-	1,476,300	1,624,100	1,666,000	1,935,100	1,790,800	2,057,200
UAMPS s404236	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II	9,769,272	603,675	571,475	603,675	593,075	603,875	948,920	1,611,625	1,425,146	606,582	603,675	593,075	603,675
Total Long Term Firm Sales	96,504,943	8,410,903	6,896,895	6,819,347	6,760,329	6,734,894	6,913,573	9,519,632	9,463,416	8,538,575	8,734,882	8,810,824	9,101,675
Short Term Firm Sales													
COB	68,026,360	9,530,480	8,487,360	9,360,240	4,306,800	4,140,000	4,305,600	5,114,200	5,114,200	4,917,500	4,305,800	4,140,000	4,306,800
Four Corners	22,386,220	2,957,110	2,475,720	2,682,030	1,285,160	1,464,260	1,285,160	1,726,920	1,726,920	1,684,800	1,716,670	1,674,800	1,716,870
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	16,520,800	3,968,100	3,747,600	4,198,500	1,456,000	1,400,000	1,456,000	774,800	774,800	745,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	65,690,490	7,557,950	6,629,600	7,562,550	6,539,960	6,713,030	6,539,960	3,677,150	3,677,150	3,761,000	4,186,700	4,056,600	4,186,700
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	19,895,525	2,503,845	2,190,510	2,353,107	2,372,520	2,323,512	-	-	-	-	2,742,376	2,602,778	2,808,878
STF Trading Margin	4,782,179	398,515	398,515	398,515	398,516	398,515	398,516	398,515	398,515	398,515	398,515	398,516	398,515
Adjustment to STF Sales Revenue	(4,392,436)	(474,041)	(304,024)	(364,244)	(200,091)	(264,735)	(249,665)	(373,071)	(345,459)	(406,679)	(438,379)	(411,935)	(410,012)
Total Short Term Firm Sales	194,909,158	26,441,959	23,765,461	26,190,898	16,067,664	16,164,582	13,735,890	11,616,513	11,546,126	11,099,936	12,911,483	12,462,858	13,004,348
System Balancing Sales													
COB	74,453,281	8,391,006	6,915,062	6,851,700	5,567,328	4,324,314	3,554,527	5,106,553	6,248,009	5,517,331	6,327,896	7,959,334	9,666,122
Four Corners	141,499,835	16,026,152	12,111,980	8,659,764	9,732,154	8,761,382	7,373,663	13,566,016	13,531,819	10,692,761	15,811,856	14,072,279	11,160,227
Mid Columbia	95,590,444	9,605,889	2,568,497	3,456,971	761,072	50,475	311,111	11,176,559	6,657,473	16,720,382	14,668,423	12,896,121	12,523,473
Mona	17,160,121	1,916,760	549,490	1,504,816	1,273,191	1,316,467	1,216,340	984,162	1,256,992	1,973,556	1,631,421	1,646,606	1,905,116
Palo Verde	65,586,532	3,009,702	2,921,623	2,397,675	5,512,995	4,895,774	7,264,716	7,690,030	5,099,566	6,576,925	7,457,616	6,220,012	6,519,900
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	394,316,013	37,148,509	25,066,651	22,870,927	22,846,739	19,348,391	19,742,359	38,527,321	34,795,658	43,460,956	45,895,112	42,796,551	41,996,838
Adjustment to Secondary Sales Revenue	55,979,012	5,041,377	4,639,270	4,542,072	3,697,043	3,373,880	3,180,563	4,754,577	4,402,076	5,185,420	5,586,888	5,240,671	5,225,357
Total Special Sales For Resale	741,709,126	78,042,746	60,366,297	60,323,044	49,371,795	45,621,758	43,572,184	64,320,243	60,207,875	68,304,695	73,128,166	69,119,903	69,328,216

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	9,758,544	182,936	668,998	1,086,246	1,528,815	1,588,035	2,098,447	1,217,641	385,080	442,197	277,524	186,896	176,149
Blanding Purchase	19,725	1,675	1,513	1,675	1,621	1,675	1,621	1,675	1,675	1,621	1,675	1,621	1,675
Combine Hills	3,911,516	374,287	244,282	432,546	304,814	283,008	340,525	326,830	324,299	309,038	331,759	369,943	270,184
Deseret Purchase	32,249,754	2,710,272	2,593,058	2,710,272	2,671,200	2,710,272	2,671,200	2,710,272	2,710,272	2,671,200	2,710,272	2,671,200	2,710,272
Douglas PUD Settlement	1,894,200	95,756	92,845	125,479	174,670	268,066	280,849	221,857	172,811	103,279	125,618	116,398	116,851
Gemstate	2,716,400	222,200	219,500	224,300	215,100	216,100	215,100	215,100	221,600	216,100	265,600	265,600	222,200
Georgia-Pacific Camas	7,280,700	618,361	558,520	618,361	598,414	618,361	598,414	618,361	618,361	598,414	618,361	598,414	618,361
Grant County 10 aMW purchase	6,971,139	671,459	463,806	514,203	534,854	585,061	593,363	750,640	762,483	621,574	488,377	457,778	607,540
Hermiston Purchase	92,817,337	6,898,670	6,273,026	6,675,968	6,365,705	3,876,410	3,675,064	8,609,605	8,621,202	8,533,469	8,718,884	9,041,141	9,156,170
Hurricane Purchase	328,501	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375
Idaho Power P278538	777,066	23,580	41,253	25,037	40,625	42,501	55,760	159,536	109,732	65,706	105,796	46,461	61,057
IPP Purchase	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
Kennecott Generation Incentive	8,211,540	-	-	445,008	503,581	498,523	303,486	1,875,336	2,122,795	1,717,515	745,316	-	-
LADWP 491303-4	1,161,570	-	-	-	-	-	199,840	387,190	387,190	167,350	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	1,755,360	146,280	146,280	146,260	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280
Morgan Stanley p189046	10,863,600	870,000	835,200	939,600	904,800	870,000	904,800	904,800	904,800	870,000	904,800	870,000	904,800
Morgan Stanley p272153-6-6	1,485,000	-	-	-	-	-	496,000	495,000	495,000	-	-	-	-
Morgan Stanley p272154-7	1,572,000	-	-	-	-	-	524,000	524,000	524,000	-	-	-	-
Nucor	4,610,400	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200
P4 Production	16,193,520	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460
PGE Cove	252,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
Rock River	5,041,666	814,635	485,591	490,707	384,510	387,883	277,559	197,878	239,001	310,441	444,655	605,219	623,409
Roseburg Forest Products	8,767,111	740,873	674,107	747,821	723,250	740,873	723,250	744,347	744,348	719,775	744,347	719,776	744,347
Small Purchases east	570,558	67,645	52,768	46,480	44,319	37,967	35,152	32,262	36,915	32,877	89,197	43,403	51,774
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	10,935,525	-	-	-	-	-	1,183,706	1,054,534	1,080,289	1,421,602	1,785,496	2,005,586	2,404,313
Tri-State Purchase	11,267,375	947,372	875,546	854,630	949,689	903,037	899,905	981,755	1,019,304	953,741	925,205	986,408	990,803
Weyerhaeuser Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek	9,746,726	722,591	570,183	1,135,230	1,093,009	1,065,499	830,533	810,703	760,900	707,747	612,757	601,036	638,537
Long Term Firm Purchases Total	276,469,441	21,705,782	20,533,751	23,346,833	21,082,067	18,745,364	21,129,043	26,932,591	28,355,207	24,506,875	23,989,107	23,770,109	24,393,712
Seasonal Purchased Power													
Morgan Stanley p244840	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p244841	-	-	-	-	-	-	-	-	-	-	-	-	-
UBS p268850	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	4,026,592	387,407	466,359	612,462	697,499	700,649	513,945	157,972	74,754	82,334	58,899	87,379	207,914
QF Idaho	4,477,849	298,760	267,681	340,095	361,922	511,157	556,164	442,079	348,334	324,612	350,631	340,163	316,651
QF Oregon	19,440,841	1,664,969	1,749,989	1,957,540	2,036,616	1,933,090	1,632,405	1,333,552	1,226,909	1,272,966	1,303,729	1,404,423	1,723,649
QF Utah	705,089	52,109	59,151	58,426	67,055	70,420	68,201	56,369	54,041	52,715	65,060	56,660	42,865
QF Washington	1,931,867	160,049	147,934	154,519	161,333	164,376	172,564	174,469	162,340	158,197	152,351	156,319	147,416
QF Wyoming	725,034	15,375	14,501	14,044	36,135	109,333	111,447	119,164	116,964	106,725	47,724	16,162	14,461
Biomass	27,250,062	2,309,276	2,111,600	2,309,276	2,243,384	2,309,276	2,243,384	2,309,276	2,309,276	2,243,384	2,309,276	2,243,384	2,309,276
Chevron Wind QF	2,366,482	162,406	290,656	305,686	100,462	111,340	105,631	113,425	193,751	169,764	266,464	260,825	295,090
Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas County Forest Products QF	203,637	36,936	30,191	26,914	30,090	23,523	21,853	34,128	-	-	-	-	-
D.R. Johnson	-	-	-	-	-	-	-	-	-	-	-	-	-
Evergreen BioPower QF	3,571,338	317,135	286,061	314,752	305,167	245,621	305,166	316,376	316,606	303,003	319,320	303,003	240,162
ExxonMobil QF	31,569,600	4,446,144	3,830,734	3,537,665	1,669,306	1,358,460	1,408,205	1,052,316	2,616,880	2,057,022	2,125,590	3,401,416	4,144,043
Kennecott QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,431,084	1,194,975	766,959	790,896	591,376	496,443	361,689	401,636	538,656	634,302	711,923	630,892	1,110,937
Mountain Wind 2 QF	12,196,479	1,744,137	1,073,230	1,120,541	805,550	864,193	689,661	767,197	637,420	799,895	647,360	1,116,176	1,513,130
Oregon Wind Farm QF	10,337,165	594,602	656,513	841,610	1,032,036	1,043,362	1,213,161	1,235,385	949,001	767,972	780,296	907,034	316,982
Simplot Phosphates	3,796,797	321,620	295,166	321,520	312,742	321,520	312,742	321,520	321,520	312,742	321,520	312,742	321,520
Spanish Fork Wind 2 QF	2,946,280	246,059	193,055	176,077	170,306	164,745	234,246	364,566	374,299	261,821	227,354	233,241	293,665
Sunnyside	24,652,043	2,095,102	1,964,811	1,534,959	2,053,722	2,092,596	2,062,618	2,162,323	2,250,965	2,122,657	1,692,840	2,146,757	2,231,093
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Weyerhaeuser QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	158,631,216	16,246,963	14,203,413	14,416,201	12,616,717	12,530,114	12,033,122	11,403,976	12,693,619	11,660,101	11,760,346	13,617,563	15,226,683
Mid-Columbia Contracts													
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach	4,240,725	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394
Douglas - Wells	4,812,738	399,793	399,793	399,793	399,793	399,793	399,793	399,793	399,793	403,596	403,596	403,596	403,596
Grant Displacement	12,134,659	672,362	615,626	649,200	1,143,931	1,197,604	999,476	1,170,453	963,543	954,226	990,197	1,049,234	1,126,964
Grant Reasonable	(14,406,120)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)
Grant Surplus	1,790,608	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	8,572,611	574,276	517,622	551,094	845,626	899,498	701,371	872,347	665,437	659,927	695,697	754,934	834,663
Total Long Term Firm Purchases	443,673,470	38,627,020	35,254,686	38,314,126	34,626,609	32,174,977	33,863,535	39,208,914	39,714,463	36,826,904	36,465,349	38,342,606	40,456,276

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Storage & Exchange													
APGI/Colockum Capacity Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	1,411,140	116,430	116,430	116,430	116,430	116,430	116,430	118,760	118,760	118,760	118,760	118,760	118,760
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Peaking	47,058,000	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500
BPA So. Idaho Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	3,600,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
PSCO FC III Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
TransAlta p371343/s371344	(1,644,000)	(186,000)	(168,000)	(180,000)	-	-	-	(186,000)	(186,000)	(180,000)	(186,000)	(180,000)	(186,000)
Total Storage & Exchange	50,425,140	4,151,930	4,189,930	4,151,930	4,337,930	4,337,930	4,337,930	4,154,260	4,154,260	4,160,260	4,154,260	4,160,260	4,154,260
Short Term Firm Purchases													
COB	1,834,300	595,550	498,600	540,150	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	38,615,272	-	-	-	-	-	-	13,480,136	13,419,536	9,715,600	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	10,329,900	769,500	694,800	771,900	746,200	759,500	746,200	765,700	765,700	740,000	1,207,700	1,166,000	1,207,700
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	(115,269,391)	(11,807,043)	(11,967,918)	(15,281,015)	(11,562,058)	(13,784,002)	(13,047,330)	(6,836,134)	(5,497,037)	(7,341,140)	(6,366,340)	(8,287,021)	(5,469,464)
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjustment to STF Purchase Expenses	1,016,504	47,091	67,903	70,801	85,170	74,835	73,290	201,714	169,046	93,166	32,211	41,875	59,582
Total Short Term Firm Purchases	(65,673,415)	(10,404,902)	(10,706,615)	(13,898,104)	(10,751,588)	(12,949,667)	(12,227,840)	7,609,416	8,857,245	3,207,646	(5,126,429)	(5,080,346)	(4,202,172)
System Balancing Purchases													
COB	9,556,200	521,406	53,073	100,823	252,245	1,183,458	1,245,777	4,147,162	577,868	-	515,544	166,721	792,124
Four Corners	18,303,439	1,648,911	2,334,606	4,005,261	1,740,154	350,261	132,800	899,982	1,403,723	680,985	1,032,736	1,958,868	2,215,190
Mid Columbia	35,446,900	1,258,312	2,131,751	2,989,853	6,526,496	6,440,441	5,977,129	2,431,821	2,194,924	742,247	653,457	1,842,104	2,558,567
Mona	20,709,881	180,931	2,423,630	737,278	1,763,807	1,073,366	1,786,391	5,807,910	4,452,800	496,062	744,340	487,328	755,938
Palo Verde	4,580,471	1,399,467	1,040,417	346,621	378,993	291,646	10,402	28,295	31,268	18,845	199,386	312,183	522,728
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	199,732	-	-	76,503	102,394	14,689	8,147	-	-	-	-	-	-
Adjustment for Condit	(700,000)										(233,333)	(233,333)	(233,333)
Total System Balancing Purchases	88,096,424	5,009,046	7,983,379	8,256,338	10,764,089	9,354,062	9,156,645	13,014,949	8,660,583	2,138,119	2,912,130	4,233,870	8,811,212
Adjustment to Secondary Purchase Expense	(12,954,749)	(900,144)	(865,364)	(902,313)	(1,085,437)	(953,724)	(934,041)	(2,570,732)	(2,154,394)	(1,187,606)	(410,510)	(531,125)	(759,339)
Total Purchased Power & Net Interchang	503,566,870	36,682,951	35,835,997	35,921,920	37,791,803	31,963,578	34,196,229	61,416,808	59,232,157	45,144,323	37,994,800	41,126,285	46,259,239

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Wheeling & U. of F. Expense													
Firm Wheeling	144,294,464	12,389,524	11,898,210	12,181,651	11,892,221	12,147,383	12,495,050	11,714,671	11,795,722	11,533,973	12,142,378	12,448,215	11,855,471
ST Firm & Non-Firm	274,921	11,169	12,937	2,733	12,912	11,252	41,776	71,838	56,769	23,972	15,658	5,554	8,353
Total Wheeling & U. of F. Expense	144,569,385	12,400,693	11,711,147	12,184,384	11,905,132	12,158,635	12,536,826	11,786,608	11,852,491	11,557,944	12,158,033	12,453,768	11,863,824
Coal Fuel Burn Expense													
Carbon	20,059,572	1,865,436	1,645,362	1,804,669	1,796,637	1,680,440	1,680,479	1,767,053	1,775,422	1,693,836	1,564,839	1,004,453	1,820,945
Cholla	55,207,439	4,917,368	4,401,341	2,527,983	4,781,580	4,803,113	4,884,023	4,923,909	4,948,603	4,765,072	4,929,515	4,695,637	4,869,297
Colstrip	12,944,264	1,137,301	1,028,148	1,139,057	1,102,087	1,137,301	1,102,087	1,138,179	1,138,179	883,248	917,534	1,102,087	1,139,057
Craig	20,838,403	1,793,122	1,620,206	1,650,548	1,619,498	1,786,687	1,731,708	1,792,240	1,793,403	1,732,305	1,789,061	1,738,355	1,794,271
Dave Johnston	52,577,538	4,583,722	4,142,845	4,588,443	4,440,263	4,562,996	4,410,506	4,555,608	4,555,608	4,138,016	3,582,298	4,440,263	4,588,971
Hayden	11,288,188	986,563	891,011	859,639	954,611	986,563	954,611	986,487	986,487	964,811	986,563	954,611	986,411
Hunter	112,775,720	10,136,121	9,050,102	7,362,638	9,082,726	9,484,373	9,147,975	9,790,683	9,854,429	9,472,302	9,658,680	9,636,785	10,100,025
Huntington	96,648,088	8,537,949	7,683,411	8,488,265	4,949,812	8,211,898	8,118,606	8,512,002	8,600,304	8,291,770	8,434,700	8,272,058	8,547,514
Jim Bridger	181,504,009	18,105,798	14,537,415	15,521,233	11,660,347	12,093,715	15,614,565	16,170,819	16,172,158	15,654,736	16,186,073	15,853,998	16,153,153
Naughton	81,873,772	7,181,842	6,439,178	7,126,275	5,119,462	6,891,172	6,906,745	7,139,248	7,142,297	6,907,120	7,135,809	6,937,998	7,187,610
Wyodak	20,144,777	1,784,725	1,516,289	1,791,110	1,727,740	1,772,897	1,700,065	1,714,713	1,720,822	1,700,065	1,492,282	1,329,830	1,792,469
Total Coal Fuel Burn Expense	665,861,747	59,009,947	53,057,302	52,858,860	47,214,781	53,180,954	56,011,369	58,490,941	58,887,510	56,171,062	56,857,233	55,762,053	56,959,714
Gas Fuel Burn Expense													
Chehalis	69,548,930	6,627,676	-	-	-	-	-	8,352,863	12,370,430	11,807,330	13,916,214	8,128,065	8,348,363
Currant Creek	79,283,790	7,168,576	5,567,414	8,083,869	6,078,594	5,108,917	5,703,971	7,718,381	8,429,041	7,322,900	6,341,916	6,397,272	7,385,139
Gadsby	6,297,743	-	-	-	-	-	-	2,163,801	2,585,946	1,567,997	-	-	-
Gadsby CT	9,220,013	1,018,008	549,761	-	-	-	899,040	1,577,850	1,690,013	1,229,438	928,635	647,104	889,165
Hermiston	56,036,843	5,783,821	5,201,302	5,790,874	3,335,026	901,421	898,165	5,530,760	5,542,076	5,456,195	5,637,757	5,923,358	6,038,087
Lake Side	101,444,269	8,992,444	7,020,485	7,580,048	7,663,880	6,710,029	7,818,468	9,334,740	9,929,449	9,407,800	9,808,200	8,264,416	9,117,642
Little Mountain	7,510,350	925,804	839,095	907,996	824,052	803,372	-	80,841	174,258	-	896,778	958,747	1,099,410
Total Gas Fuel Burn	329,341,938	30,516,329	19,178,057	20,362,585	17,899,332	13,623,738	14,916,834	34,759,237	40,701,210	36,782,659	37,529,600	30,316,952	32,853,706
Gas Physical	(45,851)	9,597	8,776	8,938	(23,107)	(23,296)	(21,357)	(17,677)	(16,715)	(15,363)	(20,022)	29,373	35,803
Gas Swaps	81,087,169	7,786,440	6,583,640	7,859,469	7,302,000	7,512,695	8,819,000	9,038,345	8,564,045	7,587,705	5,119,216	4,236,475	2,877,180
Clay Basin Gas Storage	(1,275,691)	(460,309)	(464,226)	(438,714)	52,384	52,364	52,384	52,384	52,364	52,384	52,384	(73,413)	(205,576)
Pipeline Reservation Fees	26,474,459	2,240,920	2,126,411	2,240,920	2,184,634	2,225,534	2,184,634	2,225,534	2,225,534	2,184,634	2,225,534	2,184,634	2,225,534
Additional Fixed Costs	12,123,654	1,315,055	724,549	769,470	694,412	673,924	842,856	1,579,361	1,152,147	1,188,217	420,221	1,246,745	1,516,696
Total Gas Fuel Burn Expense	447,705,897	41,410,032	28,167,207	30,802,667	28,109,635	23,984,958	24,794,131	47,638,963	52,678,564	47,780,216	45,326,213	37,941,767	39,103,325
Other Generation													
Blundell	3,498,000	309,935	279,847	309,753	299,784	309,935	299,784	309,844	309,844	299,784	159,952	299,784	309,753
Wind Integration Charge	7,682,475	733,991	632,977	682,370	623,935	599,565	604,178	551,790	565,296	585,179	647,287	712,069	743,851
Total Other Generation	11,180,475	1,043,926	912,825	992,123	923,719	909,500	903,962	861,834	875,140	884,963	807,239	1,011,840	1,053,604
Net Power Cost	1,031,178,049	72,504,801	69,308,180	72,236,910	76,673,076	76,555,888	84,872,333	116,872,810	123,118,006	99,233,634	79,816,352	79,174,790	87,911,489
Net Power Cost/Net System Load	17.58	[illegible]	14.76	8.24	17.01	16.77	17.55	21.50	23.02	19.24	17.41	[illegible]	[illegible]
Total Adjustment	(64,224,820)												

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Exhibit B

Net Power Cost Analysis

12 months ended December 2010

MWh

	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
SG	4,700,940	Condit	(700,000)										
SE	(60,933,760)												
Adjustments to Load													
Lewis River Hydro Losses	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Curtailment	(38,616)	(5,896)	-	-	-	-	(6,610)	(6,310)	(6,610)	(6,310)	-	-	(6,700)
Monsanto Curtailment	(42,790)	-	-	-	(295)	(589)	(1,820)	(9,817)	(8,802)	(5,169)	(4,787)	(2,652)	(9,059)
Station Service	70,811	4,141	4,619	6,050	6,195	7,218	6,770	5,966	6,951	5,953	6,234	6,492	4,222
Total Adjustments to Load	(10,496)	(1,755)	4,619	6,050	5,900	6,829	(1,460)	(10,161)	(8,461)	(5,526)	1,447	3,840	(11,617)
System Load	58,674,332	5,222,664	4,891,697	4,735,035	4,495,316	4,659,607	4,838,202	5,398,855	5,357,125	4,729,459	4,610,488	4,709,269	5,326,617
Net System Load	58,663,837	5,220,909	4,896,316	4,741,065	4,501,216	4,566,236	4,836,741	5,388,694	5,348,664	4,723,933	4,611,935	4,713,109	5,315,000
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	362,456	30,203	27,981	30,905	29,918	30,296	29,250	31,554	30,861	29,563	30,762	29,748	31,427
BPA Wind	39,096	4,900	4,108	3,978	3,091	2,916	2,366	1,774	1,681	2,210	3,230	4,069	4,772
Hurricane Sale	13,140	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095
LADWP (IPP Layoff)	613,200	52,080	47,040	52,080	50,400	52,080	50,400	52,080	52,080	50,400	52,080	50,400	52,080
PSCO	464,766	36,681	34,364	38,056	36,835	38,056	37,261	41,180	41,180	39,362	38,738	39,874	41,180
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD	350,400	40,700	14,800	-	4,400	-	-	39,900	49,300	45,000	52,300	48,400	55,600
UAMPS s404236	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II	223,876	13,938	12,588	13,938	13,488	13,938	21,580	41,813	32,893	18,343	13,938	13,488	13,938
Total Long Term Firm Sales	2,066,946	181,596	141,976	140,051	139,226	138,381	141,952	209,396	209,089	185,974	192,142	187,073	200,092
Short Term Firm Sales													
COB	857,200	127,400	112,800	124,200	52,000	50,000	52,000	62,400	62,400	60,000	52,000	50,000	52,000
Four Corners	406,200	51,600	43,200	46,800	22,800	25,800	22,800	32,800	32,800	32,000	32,800	32,000	32,800
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	268,000	58,600	55,200	61,600	20,800	20,000	20,800	10,400	10,400	10,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	1,808,800	164,600	165,600	183,000	169,800	176,000	115,800	70,000	70,000	86,000	136,200	132,000	136,200
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	3,140,200	422,200	376,800	415,600	285,200	271,800	211,200	175,600	175,600	170,000	221,000	214,000	221,000
System Balancing Sales													
COB	1,514,223	125,780	145,318	154,314	123,705	108,040	94,497	103,957	113,946	104,549	118,179	146,984	172,955
Four Corners	2,811,532	339,154	262,731	195,408	210,474	214,839	180,751	222,659	197,166	190,854	296,136	288,393	213,168
Mid Columbia	1,837,891	198,474	67,374	90,298	24,087	1,757	10,117	205,750	183,721	338,231	283,228	240,456	224,198
Mona	341,343	41,786	11,628	34,664	27,272	30,298	24,055	14,314	19,112	34,922	31,647	34,566	37,079
Palo Verde	1,275,119	65,461	64,657	58,569	122,930	106,854	128,420	117,501	88,214	119,903	153,931	126,572	122,107
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	7,779,909	770,655	541,707	533,253	508,468	461,787	437,840	664,182	582,159	788,259	883,121	838,971	769,507
Total Special Sales For Resale	12,987,057	1,374,451	1,060,483	1,089,104	912,894	871,968	790,992	1,049,178	966,848	1,144,233	1,296,263	1,240,044	1,190,599
Total Requirements	71,650,694	6,595,360	5,756,799	5,830,169	5,414,110	5,438,204	5,627,733	6,437,872	6,315,512	5,868,166	5,908,198	5,953,152	6,505,599

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	222,750	4,950	25,000	36,900	37,050	37,600	37,500	19,350	4,450	6,700	4,450	4,450	4,450
Blanding Purchase	263	22	20	22	22	22	22	22	22	22	22	22	22
Combine Hills	111,603	10,670	8,964	12,330	8,889	8,088	9,707	9,317	9,246	8,810	9,467	10,546	7,702
Deseret Purchase	785,772	66,737	60,278	66,737	64,584	66,737	64,584	66,737	66,737	64,584	66,737	64,584	66,737
Douglas PUD Settlement	66,696	3,479	3,379	4,577	6,323	9,847	10,240	6,063	6,242	3,712	4,554	4,164	4,276
Gemstate	37,448	-	-	-	-	1,487	10,146	13,379	12,455	-	-	-	-
Georgia-Pacific Camas	97,741	8,301	7,498	8,301	8,034	8,301	8,034	8,301	8,301	8,034	8,301	8,034	8,301
Grant County 10 aMW purchase	87,834	6,400	4,992	5,824	7,410	9,346	9,996	10,280	9,560	7,098	5,904	4,734	8,090
Hermiston Purchase	1,568,132	171,603	150,739	171,992	85,478	114	-	162,056	162,504	159,560	165,886	167,462	170,951
Hurricane Purchase	4,380	365	365	365	365	365	365	365	365	368	365	366	365
Idaho Power P278536	15,765	481	897	620	1,023	1,364	1,263	2,827	1,867	1,334	2,014	873	1,062
IPP Purchase	613,200	52,080	47,040	52,080	50,400	52,080	50,400	52,080	52,080	50,400	52,080	50,400	52,080
LADWP 491303-4	23,250	-	-	-	-	-	4,000	7,750	7,750	3,750	-	-	-
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p189046	246,600	20,000	19,200	21,600	20,800	20,000	20,800	20,800	20,800	20,000	20,800	20,000	20,800
PGE Cove	12,000	1,014	942	1,014	990	1,014	990	1,014	1,014	990	1,014	990	1,014
Rock River	142,099	17,329	13,886	13,830	10,837	10,363	7,823	6,677	6,736	8,750	12,538	17,058	17,571
Roseburg Forest Products	153,792	13,062	11,798	13,062	12,640	13,062	12,640	13,062	13,062	12,640	13,062	12,640	13,062
Small Purchases east	8,636	842	852	573	551	472	436	402	458	410	2,855	539	647
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	171,403	-	-	-	-	-	16,553	16,529	18,932	22,262	27,988	31,438	37,685
Tri-State Purchase	170,819	14,598	11,602	10,601	14,897	12,687	12,582	16,080	17,699	14,873	13,643	15,419	16,470
Weyerhaeuser Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek	176,896	13,112	10,349	20,599	19,833	19,334	15,070	14,711	13,807	12,842	11,119	14,536	11,587
Long Term Firm Purchases Total	4,717,779	405,045	375,299	441,028	349,724	271,942	295,141	448,822	432,067	407,155	422,386	428,259	440,892
Seasonal Purchased Power													
Morgan Stanley p244840	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p244841	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	34,068	3,297	4,002	4,681	6,169	6,236	4,473	1,336	567	477	442	706	1,759
QF Idaho	80,665	5,471	4,918	8,235	6,955	9,207	9,987	7,815	6,167	5,807	6,283	6,117	5,704
QF Oregon	229,067	21,916	20,378	22,680	23,688	22,878	19,380	16,066	14,925	15,212	15,448	16,661	20,287
QF Utah	13,468	993	1,081	1,044	1,259	1,416	1,354	1,165	1,091	1,026	1,234	1,013	799
QF Washington	13,136	1,087	989	1,048	1,099	1,288	1,161	1,193	1,103	1,073	1,031	1,060	995
QF Wyoming	11,387	159	147	144	559	1,820	1,834	1,975	1,967	1,741	739	165	148
Biomass	173,449	14,731	13,308	14,731	14,256	14,731	14,256	14,731	14,731	14,256	14,731	14,256	14,731
Chevron Wind QF	44,528	5,154	4,812	4,947	2,628	2,797	2,263	1,802	2,444	2,626	4,829	5,102	5,433
Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas County Forest Products QF	5,071	760	684	692	778	734	700	706	-	-	-	-	-
D.R. Johnson	-	-	-	-	-	-	-	-	-	-	-	-	-
Evergreen BioPower QF	67,072	6,004	5,352	6,667	5,695	4,668	5,695	5,935	5,935	5,695	6,004	5,695	4,629
ExxonMobil QF	648,960	71,424	64,512	71,424	46,080	47,616	46,080	19,968	47,616	46,080	47,616	69,120	71,424
Kennecott QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	151,796	19,721	13,198	15,012	12,392	10,117	7,121	8,376	8,227	10,957	13,581	15,767	19,306
Mountain Wind 2 QF	189,638	25,448	16,515	18,403	14,974	15,818	10,747	9,239	10,202	11,715	14,778	16,563	23,239
Oregon Wind Farm QF	161,172	9,177	10,130	12,979	16,974	18,431	18,932	19,466	14,998	12,070	12,181	14,007	4,827
Simplot Phosphates	74,480	6,324	5,712	6,324	6,120	6,324	6,120	6,324	6,324	6,120	6,324	6,120	6,324
Spanish Fork Wind 2 QF	55,562	4,484	3,589	3,500	3,695	3,438	4,611	6,114	6,123	5,203	4,608	4,816	5,480
Sunnyside	385,080	34,700	31,342	19,029	33,581	34,700	33,581	34,700	34,700	33,581	26,865	33,581	34,700
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Weyerhaeuser QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	2,338,555	230,869	200,778	208,501	195,719	199,996	168,284	154,692	177,141	173,642	176,889	212,559	219,686
Mid-Columbia Contracts													
Canadian Entitlement	(17,528)	(1,456)	(1,344)	(1,512)	(1,456)	(1,456)	(1,456)	(1,512)	(1,456)	(1,456)	(1,456)	(1,456)	(1,512)
Chelan - Rocky Reach	327,226	34,061	24,578	24,070	29,747	33,969	35,082	33,401	25,161	17,271	20,393	23,054	26,441
Douglas - Wells	252,519	28,036	18,601	18,063	23,417	27,901	27,098	26,209	19,434	13,043	15,376	17,361	19,982
Grant Displacement	439,837	29,411	28,744	29,808	42,893	53,655	51,540	48,501	33,167	30,962	31,597	31,347	32,392
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	88,890	12,394	7,118	6,926	7,050	7,477	8,129	8,115	6,444	4,999	5,891	6,888	7,880
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,090,944	100,445	75,696	77,355	101,461	121,646	120,393	112,714	82,769	84,819	71,801	76,993	84,963
Total Long Term Firm Purchases	8,147,277	738,359	661,771	726,884	648,894	593,484	603,819	718,228	691,996	646,615	670,878	717,811	745,541

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Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Storage & Exchange													
APGI/Colockum Capacity Exchange	(288,153)	(16,606)	(15,579)	(16,877)	(16,445)	(18,600)	(16,446)	(17,743)	(17,743)	(37,310)	(37,743)	(37,310)	(17,743)
APS Exchange	450	142,575	66,850	-	-	(77,900)	(137,970)	(142,380)	(142,490)	(68,760)	77,895	137,895	142,765
BPA Exchange	0	-	-	(50,000)	-	-	133,333	116,667	-	(66,067)	(66,667)	(66,667)	-
BPA FC II Storage Agreement	239	36	(34)	15	(95)	18	(64)	10	22	117	23	168	32
BPA FC IV Storage Agreement	2,229	340	(316)	141	(686)	168	(597)	95	206	1,095	212	1,473	300
BPA Peaking	0	(4,600)	(3,949)	3,126	4,403	(8,385)	(4,149)	9,255	(4,925)	3,801	(5,200)	1,380	7,246
BPA So. Idaho Exchange	39,670	3,921	4,087	3,264	2,979	2,486	3,083	3,170	3,318	2,593	3,034	3,545	4,211
Cowlitz Swift	6,534	774	3,612	(2,220)	3,764	(1,656)	(1,357)	1,212	(3,025)	2,620	2,184	(3,940)	4,566
EWEB FC I Storage Agreement	1,236	160	53	33	(39)	77	(19)	(63)	66	192	260	284	220
PSCo Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III Storage Agreement	(0)	1,240	(1,767)	(2,146)	(2,224)	(1,922)	(1,334)	(2,680)	(1,975)	1,549	3,650	3,864	2,855
Redding Exchange	(55)	11,316	10,184	10,766	10,968	(6,374)	(6,832)	(10,914)	(13,802)	(14,134)	(14,474)	11,298	11,943
SCL State Line Storage Agreement	14,486	1,857	(3,516)	10,716	9,052	(7,771)	4,559	(1,603)	(5,140)	(2,401)	1,374	6,949	490
TransAlta p371343/s371344	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	(203,365)	139,010	61,623	(43,181)	11,476	(117,867)	(27,812)	(44,864)	(184,589)	(177,406)	(35,552)	68,919	156,874
Short Term Firm Purchases													
COB	23,600	8,600	7,200	7,800	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	485,200	-	-	-	-	-	-	177,600	176,800	130,800	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	249,800	18,600	16,800	18,600	18,000	18,600	18,000	18,600	18,600	16,000	29,000	28,000	29,000
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	758,600	27,200	24,000	26,400	18,000	18,600	18,000	196,200	195,400	146,800	29,000	28,000	29,000
System Balancing Purchases													
COB	196,264	11,369	1,279	2,627	6,019	35,166	36,123	64,676	8,191	-	10,311	3,589	16,712
Four Corners	486,406	45,547	67,205	123,021	52,204	10,866	3,865	10,059	29,202	20,130	24,634	46,667	53,009
Mid Columbia	960,991	27,735	47,465	76,278	170,537	218,942	197,650	64,855	46,164	15,685	12,660	32,861	50,239
Mona	447,353	6,221	59,770	21,698	64,141	33,986	43,614	99,660	70,656	12,764	17,573	10,894	16,956
Palo Verde	124,162	36,637	27,499	9,494	11,162	9,277	424	761	840	463	5,303	6,251	14,112
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	4,729	-	-	1,743	2,336	410	240	-	-	-	-	-	-
Total System Balancing Purchases	2,219,947	126,426	203,218	234,862	296,416	308,448	281,915	240,453	155,253	48,962	70,880	102,261	151,027
Total Purchased Power & Net Interchang	10,922,460	1,026,997	940,613	944,965	972,791	802,665	675,921	1,106,017	858,061	665,972	735,005	907,011	1,082,442

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Coal Generation													
Carbon	1,188,416	111,011	97,723	107,134	106,883	97,729	98,020	104,558	105,099	100,151	93,092	58,840	108,180
Cholla	2,873,922	256,058	229,102	131,607	247,929	249,898	242,678	258,363	257,680	248,090	256,659	244,387	253,472
Colstrip	1,157,417	101,884	91,932	101,858	98,548	101,684	98,548	101,770	101,770	77,254	81,989	98,548	101,858
Craig	1,357,993	116,857	105,689	107,534	105,586	118,424	112,843	118,796	118,876	112,886	116,581	113,092	118,933
Dave Johnston	5,897,343	514,145	464,705	514,699	498,073	510,672	494,710	610,977	510,977	463,764	401,791	498,073	514,757
Hayden	633,786	55,396	50,030	36,997	53,601	55,396	53,601	55,391	55,391	53,601	55,396	53,601	55,366
Hunter	8,042,046	724,728	646,557	526,117	647,893	674,214	649,697	697,805	702,686	674,955	687,284	687,920	721,989
Huntington	6,856,495	588,126	529,228	584,638	341,097	585,603	558,722	588,208	592,507	571,194	680,558	569,818	688,798
Jim Bridger	10,294,306	913,290	824,286	880,503	661,104	685,646	885,565	917,292	917,376	888,041	917,007	887,996	916,201
Naughton	5,392,639	471,698	424,055	469,211	337,269	441,159	454,832	470,143	470,348	454,858	469,907	458,968	472,092
Wyodak	2,203,844	195,393	177,228	196,149	169,159	193,991	165,839	187,092	187,793	165,679	163,332	146,642	190,309
Total Coal Generation	45,698,110	4,048,384	3,640,435	3,656,442	3,287,143	3,692,416	3,835,295	4,004,393	4,018,501	3,830,872	3,823,575	3,814,880	4,046,974
Gas Generation													
Chehalis	1,607,195	145,347	-	-	-	-	-	210,862	305,638	288,541	333,798	164,129	158,889
Currant Creek	2,044,347	182,246	140,839	157,686	168,551	139,610	165,616	207,020	222,121	191,612	169,006	152,185	157,956
Gadsby	96,698	-	-	-	-	-	-	33,559	39,530	23,608	-	-	-
Gadsby CT	128,469	12,863	8,925	-	-	-	9,362	24,260	25,740	17,484	12,730	7,844	9,460
Hermiston	1,588,132	171,603	150,739	171,992	85,476	114	-	162,058	162,504	159,560	185,886	187,452	170,951
Lake Side	2,760,047	241,805	186,416	206,864	227,526	194,777	217,457	263,013	275,985	258,222	272,941	208,309	204,750
Little Mountain	83,357	10,371	9,367	10,371	10,036	9,630	-	864	1,920	-	10,371	10,036	10,371
Total Gas Generation	8,286,241	764,235	496,286	546,912	491,590	344,131	382,436	901,646	1,033,419	938,926	984,530	709,754	712,376
Hydro Generation													
West Hydro	3,727,038	472,123	439,440	386,912	410,519	340,238	281,848	182,298	173,310	217,453	159,926	267,746	395,226
East Hydro	308,123	17,301	17,095	30,231	30,539	37,018	36,738	42,039	36,171	19,642	12,909	13,577	15,861
Total Hydro Generation	4,035,162	469,424	466,535	417,143	441,058	377,257	317,586	224,337	209,481	237,095	172,838	281,323	411,088
Other Generation													
Blundell	181,827	16,111	14,547	16,101	15,583	16,111	15,583	16,106	16,106	15,583	6,314	15,583	16,101
Blundell Bottoming Cycle	86,961	7,705	6,957	7,700	7,453	7,705	7,453	7,703	7,703	7,453	3,976	7,453	7,700
Total Blundell	268,787	23,816	21,504	23,801	23,036	23,816	23,036	23,809	23,809	23,036	12,291	23,036	23,801
Foote Creek I	102,699	12,892	10,506	10,105	7,611	7,605	5,885	4,253	4,488	6,260	9,076	11,269	12,794
Glenrock Wind	332,471	38,809	28,625	30,312	27,213	22,675	22,529	19,189	20,690	24,548	29,268	32,442	38,172
Glenrock III Wind	124,409	13,846	10,745	11,363	10,181	8,432	8,385	7,094	7,678	9,169	10,960	12,182	14,375
Goodnoe Wind	286,687	13,956	18,183	31,076	22,609	24,419	28,225	27,556	23,970	18,281	23,542	20,857	14,214
High Plains Wind	309,370	35,480	27,001	29,176	25,636	26,751	20,558	18,978	17,585	20,555	22,727	31,025	35,802
Leaning Juniper 1	305,473	16,176	17,454	29,577	23,680	31,823	33,873	35,958	30,532	25,784	24,389	18,181	18,066
Marengo I	393,136	32,850	33,648	35,285	36,941	33,338	32,512	31,293	30,373	29,681	32,407	31,668	34,139
Marengo II	187,226	25,913	18,628	19,890	13,928	12,361	15,227	12,975	13,096	12,325	12,202	16,668	14,013
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	349,596	43,929	30,606	36,878	28,476	25,498	21,961	17,024	19,928	21,806	29,584	35,802	40,304
Seven Mile II Wind	68,862	9,653	6,029	7,264	5,215	5,022	4,328	3,353	3,925	4,256	5,827	7,052	7,939
Total Wind Generation	2,440,129	240,504	201,425	240,925	198,492	197,921	193,469	175,670	172,242	172,466	199,981	217,147	229,919
Total Other Generation	2,708,917	264,319	222,929	264,726	221,528	221,737	216,494	199,479	196,050	195,501	212,251	240,183	253,720
Total Resources	71,650,869	6,595,359	5,756,799	5,830,189	5,414,109	5,438,205	5,827,732	6,437,871	6,315,512	5,868,166	6,908,198	5,953,161	6,606,598

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Exhibit B

Net Power Cost Analysis

"The Rack"

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Fuel Burned (MMBtu)													
Carbon	13,707,576	1,274,733	1,124,348	1,233,209	1,227,721	1,134,650	1,134,677	1,207,505	1.213,223	1,157,472	1,089,323	686,387	1.244,331
Cholla	31,062,195	2,766,734	2,476,389	1,422,352	2,679,078	2,702,446	2,624,189	2,770,418	2,784,313	2,681,046	2,773,573	2,641,978	2,739,681
Colstrip	12,493,832	1.097,726	992,369	1,099,420	1,063,737	1,097,726	1,063,736	1,096,573	1,096,572	833,209	865,607	1,063,736	1,099,420
Craig	13,720,601	1,180,645	1,066,769	1,086,768	1,066,322	1,176,406	1,140,204	1,180,063	1,180,829	1,140,598	1,177,970	1,142,607	1,181,399
Dave Johnston	65,580,713	5,715,593	5,165,856	5,721,474	5,538,704	5,877,297	5,499,613	5,680,547	5,680,552	5,157,337	4,468,905	5,538,707	6,722,129
Hayden	6,708,726	586,329	529.541	392,033	567,339	586,329	567,340	586,284	586,284	567,339	588,329	567,340	586,239
Hunter	85,290,013	7,665,752	6,844,410	5,568,210	6,869,079	7,172,636	6,916,428	7,404,499	7,452,706	7,163,712	7,304,600	7,287,333	7,636,448
Huntington	66,667,515	5.891,208	6,301,579	5,856,937	3,415,381	5,666,100	5,601,868	5,873,309	6,934,241	5,721,354	5,819,966	5,707,750	5,897.822
Jim Bridger	107,557,865	9,544,145	8,614,748	9,197,748	6,909,820	7,166,636	9,253,058	9,562,880	9,583,470	9,276,863	9,579,881	9,278,422	9,672,218
Naughton	56,269,979	4,922,173	4,425,497	4,897,041	3,518,498	4,598,668	4,746,646	4,908,643	4,908,741	4,747,106	4,904,279	4,768,329	4,926,137
Wyodak	26,460,995	2,344,308	2,125,886	2,352,694	2,269,455	2,328,764	2,233,121	2,252,348	2,260,111	2,233,121	1,980,138	1,746,786	2,364,486
Chehalis	11,492,394	1,041,235	-	-	-	-	-	1,505,714	2,191,962	2,066,790	2,386,127	1,168,567	1,133,001
Currant Creek	15,075,127	1,354,154	1,047,997	1,171,946	1,249,036	1,040,440	1,139,427	1,515,783	1,626,404	1,395,347	1,237,040	1,126,238	1,169,318
Gadsby	1,176,765	-	-	-	-	-	-	410,904	476,846	289,006	-	-	-
Gadsby CT	1.663,545	166.011	100,104	-	-	-	135,001	299,633	316,384	224,945	175,173	110,488	136,806
Hermiston	11,308,218	1,235,151	1,067,884	1,236,934	616,069	823	-	1.171,178	1,174,037	1,152,324	1,198,231	1,204,287	1,231,303
Lake Side	19,147,811	1,684,930	1,310,828	1,448,389	1,562,877	1,365,813	1,509,019	1,818,462	1,900,480	1,778,165	1,897,779	1,445,797	1,436,851
Little Mountain	1,362,832	169,164	152.789	169,165	163,700	158,135	-	15,352	32,519	-	169,164	163,700	169,155
Burn Rate (MMBtu/MWh)													
Carbon	11.534	11.483	11,506	11.511	11.487	11.810	11.576	11.549	11.544	11.657	11.487	11.665	11.502
Cholla	10.806	10.805	10.809	10.808	10.806	10.814	10.813	10.807	10.805	10.807	10.806	10.811	10.809
Colstrip	10.795	10.796	10.795	10.794	10.794	10.795	10.794	10.795	10.795	10.785	10.804	10.794	10.794
Craig	10.104	10.103	10.103	10.106	10.099	10.105	10.104	10.104	10.103	10.104	10.104	10.103	10.103
Dave Johnston	11.117	11.117	11.116	11.116	11.116	11.117	11.117	11.117	11.117	11.121	11.117	11.116	11.116
Hayden	10.686	10.584	10.584	10.596	10.585	10.584	10.585	10.584	10.584	10.685	10.584	10.585	10.586
Hunter	10.606	10.577	10.566	10.584	10.602	10.639	10.645	10.811	10.606	10.614	10.628	10.593	10.580
Huntington	10.016	10.017	10.018	10.018	10.013	10.016	10.026	10.019	10.016	10.016	10.025	10.017	10.017
Jim Bridger	10.448	10.450	10.451	10.446	10.452	10.452	10.449	10.447	10.447	10.448	10.447	10.446	10.448
Naughton	10.435	10.436	10.436	10.437	10.432	10.424	10.436	10.436	10.436	10.436	10.437	10.435	10.435
Wyodak	12.007	11.998	11.994	11.994	11.998	12.005	12.014	12.039	12.035	12.014	12.001	11.994	11.994
Chehalis	7.151	7.164	0.000	0.000	0.000	0.000	0.000	7.141	7.172	7.163	7.145	7.120	7.131
Currant Creek	7.374	7.430	7.441	7.432	7.410	7.462	7.322	7.322	7.322	7.286	7.320	7.414	7.403
Gadsby	12.190	0.000	0.000	0.000	0.000	0.000	0.000	12.244	12.113	12.243	0.000	0.000	0.000
Gadsby CT	13.312	14.460	14.456	0.000	0.000	0.000	14.419	12.351	12.252	12.866	13.761	14.455	14.462
Hermiston	7.211	7.198	7.217	7.192	7.207	7.242	0.000	7.227	7.225	7.222	7.232	7.192	7.203
Lake Side	6.937	6.968	6.957	7.002	6.868	6.959	6.939	6.914	6.887	6.886	6.953	6.941	7.013
Little Mountain	16.349	16.311	16.311	16.311	16.311	16.421	0.000	17.360	16.941	0.000	16.311	16.311	16.311
Average Fuel Cost ($/MMBtu)													
Carbon	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463
Cholla	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777
Colstrip	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036
Craig	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519
Dave Johnston	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802
Hayden	1.663	1.663	1.663	1.663	1.663	1.663	1.663	1.663	1.663	1.663	1.663	1.663	1.663
Hunter	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322
Huntington	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449
Jim Bridger	1.686	1.686	1.686	1.686	1.686	1.686	1.686	1.686	1.686	1.686	1.686	1.686	1.686
Naughton	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455
Wyodak	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761
Chehalis	5.929	6.365	6.147	5.549	5.274	5.322	5.424	5.547	5.644	5.713	5.835	6.956	7.367
Currant Creek	5.266	5.294	5.312	6.191	4.865	4.910	5.006	5.092	5.183	5.248	6.127	5.670	6.299
Gadsby	5.444	5.473	5.492	5.368	5.034	5.080	5.176	5.266	5.359	5.425	5.301	5.857	6.499
Gadsby CT	5.444	5.473	5.492	5.368	5.034	5.080	5.176	5.266	5.359	5.425	5.301	5.857	6.499
Hermiston	3.992	3.966	3.956	3.956	3.966	3.966	3.956	3.958	3.958	3.958	3.956	4.173	4.173
Lake Side	5.309	6.337	5.356	5.233	4.904	4.950	5.047	5.133	5.225	5.291	5.166	5.716	6.350
Little Mountain	5.444	5.473	5.492	5.368	5.034	5.080	5.176	5.266	5.359	5.425	5.301	5.857	6.499

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010

	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Peak Capacity (Nameplate)													
Blundell	23	23	23	23	23	23	23	23	23	23	23	23	23
Blundell Bottoming Cycle	11	11	11	11	11	11	11	11	11	11	11	11	11
Carbon	172	172	172	172	172	172	172	172	172	172	172	172	172
Cholla	387	387	387	387	387	387	387	387	387	387	387	387	387
Colstrip	148	148	148	148	148	148	148	148	148	148	148	148	148
Craig	166	166	166	166	166	166	166	166	166	166	166	166	166
Dave Johnston	762	762	762	762	762	757	757	757	757	757	757	762	762
Hayden	78	78	78	78	78	78	78	78	78	78	78	78	78
Hunter	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,118	1,118	1,123	1,123	1,123	1,123
Huntington	895	895	895	895	895	895	895	895	895	895	895	895	895
Jim Bridger	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413
Naughton	700	700	700	700	700	696	695	695	695	696	695	700	700
Wyodak	280	279	280	280	279	277	274	267	266	274	276	280	280
Chehalis	529	529	526	524	522	514	509	500	500	507	520	527	529
Currant Creek	549	549	549	548	547	543	539	533	534	540	545	549	549
Gadsby	231	231	231	231	231	231	231	231	231	231	231	231	231
Gadsby CT	123	123	123	123	121	121	121	117	117	121	121	123	123
Hermiston	248	248	248	248	241	237	235	232	232	237	241	248	248
Lake Side	584	584	577	569	561	576	572	568	569	574	557	570	580
Little Mountain	14	14	14	14	14	13	13	12	12	13	14	14	14
Capacity Factor													
Blundell	90.2%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	48.6%	94.1%	94.1%
Carbon	78.9%	86.7%	84.5%	83.7%	86.3%	76.4%	79.2%	81.7%	82.1%	60.9%	72.7%	47.5%	84.5%
Cholla	84.8%	86.9%	86.1%	45.7%	89.0%	86.8%	87.1%	89.0%	89.5%	89.0%	89.1%	87.7%	86.0%
Colstrip	89.3%	92.3%	92.4%	92.5%	92.5%	92.3%	92.5%	92.4%	92.4%	72.5%	74.4%	92.5%	92.5%
Craig	93.7%	94.9%	94.9%	87.3%	86.8%	94.6%	94.7%	94.9%	94.9%	94.7%	94.7%	94.9%	95.0%
Dave Johnston	88.6%	90.7%	90.8%	90.8%	90.6%	90.7%	90.8%	90.7%	90.7%	85.1%	71.3%	90.8%	90.8%
Hayden	92.8%	96.6%	95.4%	63.8%	95.4%	95.5%	95.4%	95.4%	95.4%	98.4%	95.5%	95.4%	95.4%
Hunter	81.8%	86.7%	85.7%	63.0%	80.1%	80.7%	80.4%	83.9%	84.5%	83.5%	82.2%	85.1%	86.4%
Huntington	84.9%	86.3%	88.0%	87.8%	82.9%	84.9%	86.7%	88.0%	89.0%	88.8%	87.2%	88.4%	88.4%
Jim Bridger	83.1%	88.9%	86.8%	83.7%	65.0%	85.2%	87.0%	87.2%	87.2%	87.3%	87.2%	87.3%	87.1%
Naughton	88.3%	90.6%	90.1%	90.1%	66.9%	85.3%	90.9%	90.9%	91.0%	90.9%	90.9%	90.7%	90.6%
Wyodak	91.1%	94.1%	94.2%	94.2%	94.2%	94.1%	94.2%	94.2%	94.2%	94.2%	79.0%	72.2%	94.2%
Chehalis	36.5%	36.8%	-	-	-	-	-	56.7%	62.2%	79.0%	68.3%	43.3%	40.4%
Currant Creek	42.9%	44.6%	38.2%	38.7%	42.8%	34.6%	40.1%	52.2%	55.9%	49.3%	41.7%	38.6%	38.7%
Gadsby	4.8%	-	-	-	-	-	-	19.6%	23.1%	14.2%	-	-	-
Gadsby CT	11.9%	14.1%	6.4%	-	-	-	10.6%	27.9%	29.6%	20.1%	14.2%	8.6%	10.3%
Hermiston	74.4%	93.0%	91.2%	94.0%	49.3%	0.1%	-	93.9%	94.1%	93.5%	92.4%	94.5%	92.7%
Lake Side	56.1%	55.7%	48.6%	48.9%	56.3%	45.5%	82.8%	62.2%	65.2%	62.5%	65.9%	50.8%	47.4%
Little Mountain	71.0%	99.6%	99.6%	99.6%	99.8%	99.6%	-	9.9%	21.5%	-	99.6%	99.6%	99.6%
Foote Creek 1	35.9%	53.1%	47.9%	41.6%	32.4%	31.3%	25.0%	17.5%	18.4%	26.7%	37.4%	48.0%	52.7%
Glenrock Wind	38.3%	50.0%	43.0%	41.2%	38.2%	30.8%	31.6%	26.1%	28.1%	34.4%	39.7%	45.5%	51.8%
Glenrock III Wind	36.4%	47.7%	41.0%	39.2%	38.3%	29.1%	29.9%	24.4%	26.5%	32.7%	37.8%	43.4%	49.5%
Goodnoe Wind	32.4%	20.0%	28.8%	44.4%	33.4%	34.9%	41.7%	39.4%	34.3%	27.0%	33.7%	30.8%	20.3%
High Plains Wind	35.7%	48.2%	40.6%	39.6%	38.0%	38.3%	28.8%	23.0%	23.9%	28.8%	30.9%	43.5%	48.7%
Leaning Juniper 1	34.7%	21.6%	26.8%	39.6%	32.7%	42.6%	46.6%	48.1%	40.8%	35.6%	32.6%	26.1%	24.2%
Marengo I	32.0%	31.4%	36.7%	33.6%	35.6%	31.9%	32.2%	30.0%	29.1%	29.4%	31.0%	31.3%	32.7%
Marengo II	30.4%	49.6%	39.5%	38.1%	27.6%	23.7%	30.1%	24.6%	25.1%	24.4%	23.4%	33.0%	28.8%
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	40.3%	59.6%	46.0%	50.1%	37.1%	34.6%	30.8%	23.1%	27.1%	30.3%	40.2%	50.2%	54.7%
Seven Mile II Wind	40.3%	59.6%	46.0%	50.1%	37.1%	34.6%	30.8%	23.1%	27.1%	30.3%	40.2%	50.2%	54.7%

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Wind Integration Charge													
Foote Creek I	102,699	12,892	10,608	10,105	7,611	7,605	5,865	4,253	4,466	6,260	9,075	11,269	12,794
Glenrock Wind	332,471	36,809	26,625	30,312	27,213	22,675	22,629	19,169	20,690	24,546	29,266	32,442	38,172
Glenrock III Wind	124,409	13,846	10,745	11,363	10,181	8,432	8,365	7,094	7,676	9,169	10,960	12,182	14,375
High Plains Wind	309,370	35,460	27,001	29,176	25,636	26,751	20,556	16,978	17,585	20,555	22,727	31,025	35,902
Marengo I	393,136	32,850	33,648	35,285	35,941	33,336	32,512	31,293	30,373	29,681	32,407	31,668	34,139
Marengo II	187,226	25,913	18,628	19,890	13,929	12,361	15,227	12,875	13,096	12,325	12,202	16,669	14,013
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	349,598	43,929	30,606	36,878	26,476	26,496	21,961	17,024	19,926	21,606	29,584	35,802	40,304
Seven Mile II Wind	68,682	8,653	6,029	7,264	5,215	5,022	4,326	3,363	3,925	4,266	5,827	7,052	7,939
Combine Hills	111,503	10,670	8,964	12,330	8,689	8,068	9,707	9,317	9,246	8,810	9,457	10,548	7,702
Rock River	142,099	17,329	13,686	13,830	10,837	10,363	7,823	5,577	8,736	8,750	12,538	17,058	17,571
Three Buttes Wind	171,403	-	-	-	-	-	18,553	16,529	16,932	22,282	27,986	31,436	37,685
Wolverine Creek	176,698	13,112	10,346	20,599	19,833	19,334	15,070	14,711	13,607	12,842	11,119	14,536	11,567
BPA FC II Generation	5,650	709	578	556	419	418	323	234	246	344	499	620	704
BPA FC IV Generation	52,734	6,619	5,394	5,189	3,906	3,905	3,012	2,164	2,293	3,214	4,660	5,786	6,569
EWEB FC I Generation	27,563	3,460	2,820	2,712	2,043	2,041	1,574	1,141	1,198	1,680	2,436	3,024	3,434
PSCo FC III Generation	78,101	9,929	8,092	7,763	5,862	5,857	4,517	3,276	3,439	4,822	6,990	8,680	9,854
Long Hollow	333,438	38,586	34,980	29,681	26,391	22,034	22,320	13,777	17,963	21,061	27,716	34,649	42,273
State Line generation	491,423	45,306	35,245	47,394	42,827	40,883	49,269	39,940	41,770	36,908	39,256	38,482	35,346
--	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	44,526	5,154	4,812	4,947	2,526	2,797	2,253	1,602	2,444	2,626	4,829	6,102	5,433
Mountain Wind 1 QF	151,796	18,721	13,196	15,012	12,392	10,117	7,121	6,376	8,227	10,967	13,581	16,787	19,306
Mountain Wind 2 QF	189,638	25,446	16,515	16,403	14,974	15,818	10,747	9,239	10,202	11,715	14,776	18,583	23,239
Oregon Wind Farm QF	161,172	9,177	10,130	12,979	15,974	16,431	18,932	19,466	14,998	12,070	12,181	14,007	4,627
Spanish Fork Wind 2 QF	55,562	4,464	3,689	3,500	3,595	3,438	4,611	6,114	8,123	5,203	4,608	4,616	5,460
Subtotal Wind Generation	4,082,274	420,075	332,237	375,187	324,374	303,183	307,194	261,639	273,383	290,873	344,680	401,001	428,649
Generation subject to BPA Wind Integration Charges (included in wheeling)													
Goodnoe Wind	266,887	13,956	18,183	31,076	22,609	24,419	28,225	27,568	23,970	18,281	23,542	20,857	14,214
Leaning Juniper 1	305,473	16,176	17,454	29,577	23,680	31,823	33,873	35,958	30,532	25,784	24,369	18,161	18,066
Total Generation (MWh)	4,634,634	450,207	367,874	435,840	370,663	359,424	369,291	325,153	327,880	334,737	392,592	440,039	460,929
Wind Integration Charge $/MWh		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
BPA Wind Integration Charge per kW-month		1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Company Wind Integration Charge	4,671,815	483,086	382,072	431,465	373,030	348,660	353,273	300,885	314,391	334,274	396,382	461,161	492,946
Goodnoe Wind	1,455,120	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260
Leaning Juniper 1	1,555,740	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645
Total Wind Integration Charge ($)	7,682,475	733,991	632,977	682,370	623,935	599,565	604,178	551,790	565,296	585,179	647,287	712,066	743,851
Additional Fixed Costs													
Gadsby	496,359	-	-	-	-	-	-	176,747	167,049	150,563	-	-	-
Gadsby CT	226,355	32,197	24,587	-	-	-	18,392	18,120	16,439	19,071	22,165	30,338	43,046
Chehalis	2,149,521	381,912	-	-	-	-	-	515,911	84,653	154,249	-	438,202	574,595
Additional O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Startup Fuel	2,149,521	381,912	-	-	-	-	-	515,911	84,653	154,249	-	438,202	574,595
Currant Creek	3,995,259	374,425	290,698	319,785	288,599	280,084	342,649	380,153	366,563	359,218	315,818	323,423	373,645
Additional O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Startup Fuel	3,995,259	374,425	290,898	319,785	288,599	280,084	342,649	380,153	366,563	359,218	315,818	323,423	373,645
Lake Side	5,256,160	526,521	409,064	449,685	405,813	393,840	481,815	506,429	515,444	505,117	82,238	454,782	625,412
Additional O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Startup Fuel	5,256,160	526,521	409,064	449,685	405,813	393,840	481,815	506,429	515,444	505,117	82,238	454,782	625,412
Total Fixed Costs	12,123,654	1,316,056	724,549	769,470	694,412	673,924	842,656	1,579,361	1,152,147	1,188,217	420,221	1,246,745	1,516,898

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010

Mills / kWh

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	33.13	33.14	34.48	32.76	33.30	33.08	33.69	32.41	32.77	33.60	32.83	33.40	32.47
BPA Wind	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30
Hurricane Sale	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
LADWP (IPP Layoff)	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57
PSCO	70.01	70.03	72.38	70.33	70.98	70.33	70.74	68.90	68.90	69.71	70.00	69.47	68.90
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD	37.00	37.00	37.00	-	37.00	-	-	37.00	37.00	37.00	37.00	37.00	37.00
UAMPS s404236	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II	43.64	43.33	45.40	43,33	43.97	43.33	43.97	43.33	43.33	43.97	43.33	43.97	43.33
Total Long Term Firm Sales	46.69	46.32	48.58	46.69	48.58	48.67	48.70	45.46	46.26	45.91	45.46	46.03	45.49
Short Term Firm Sales													
COB	79.36	74.81	75.24	76.36	82.80	82.80	82.80	81.96	81.96	81.96	82.80	82.80	82.80
Four Corners	54.84	57.31	57.31	57.31	56.37	56.37	56.37	52.65	52.65	52.65	52.34	52.34	52.34
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	69.11	67.72	67.89	67.94	70.00	70.00	70.00	74.50	74.50	74.50	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	40.68	40.94	41.24	41.33	38.56	38.14	56.57	56.39	55.39	55.31	30.74	30.75	30.74
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	62.07	62.63	63.07	62.99	60.59	59.47	65.04	65.60	65.75	65.29	58.42	58.24	58.64
System Balancing Sales													
COB	49.17	50.81	47.59	43.10	45.00	40.03	37.82	49.14	54.83	52.77	53.55	63.42	57.17
Four Corners	50.33	47.28	46.10	44.32	46.24	40.78	40.79	60.93	66.63	56.08	53.39	48.80	52.35
Mid Columbia	52.02	49.41	44.77	38.28	31.60	28.74	30.75	54.33	62.88	55.35	51.78	53.63	55.88
Mona	50.33	45.85	47.28	43.41	46.08	43.45	50.65	68.76	65.88	56.51	61.55	47.70	51.38
Palo Verde	51,44	45.98	45.19	40.94	44.85	45.82	56.73	65.45	57.81	54.66	48.45	49.14	53.39
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	50.68	48.20	46.27	42.51	44.93	41.90	46.09	58.01	59.77	56.16	51.97	51.01	54.58
Total Special Sales For Resale	57.11	56.78	56.93	55.39	54.06	52.32	55.08	61.31	62.27	59.69	56.41	55.74	58.23

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	43.80	32.92	26.76	28.90	41.26	41.81	55.91	62.93	65.53	66.00	62.36	37.46	39.56
Blanding Purchase	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Combine Hills	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08
Deseret Purchase	41.04	40.61	43.02	40.61	41.36	40.61	41.36	40.61	40.61	41.36	40.61	41.36	40.61
Douglas PUD Settlement	27.57	27.62	27.42	27.42	27.61	27.58	27.43	27.45	27.69	27.82	27.59	27.82	27.79
Gemstate	72.54	-	-	-	-	146.63	21.20	16.08	17.78	-	-	-	-
Georgia-Pacific Camas	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49
Grant County 10 aMW purchase	79.55	89.29	92.91	88.29	72.16	62.60	59.36	73.02	61.65	87.67	62.72	96.70	99.76
Hermiston Purchase	59.19	51.68	64.86	51.61	74.47	34,124.91	-	53.13	53.05	63.46	52.62	53.99	63.56
Hurricane Purchase	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Idaho Power P278538	49.29	49.02	45.99	40.38	39.71	31.16	43.48	54.51	58.77	49.25	52.63	53.22	58.43
IPP Purchase	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57
LADWP 491303-4	49.96	-	-	-	-	-	49.96	49.96	49.96	49.96	-	-	-
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p189046	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50
PGE Cove	21.00	20.71	22.29	20.71	21.21	20.71	21.21	20.71	20.71	21.21	20.71	21.21	20.71
Rock River	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
Roseburg Forest Products	57.01	56.72	57.14	57.25	57.22	56.72	57.22	56.99	56.99	56.94	56.99	56.94	56.99
Small Purchases east	66.07	80.37	80.93	81.09	80.49	80.49	80.66	60.31	80.53	79.76	33.59	60.58	80.00
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	63.80	-	-	-	-	-	63.80	63.80	63.80	63.80	63.80	63.80	63.80
Tri-State Purchase	65.96	64.90	76.12	60.62	64.62	71.16	71.89	61.05	67.59	64.13	67.82	62.68	60.18
Weyerhaeuser Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11
Long Term Firm Purchases Total	58.60	53.59	54.71	52.94	60.22	68.93	71.59	60.01	61.00	60.19	56.79	56.50	55.33
Seasonal Purchased Power													
Morgan Stanley p244840	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p244841	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	118.20	117.51	116.29	134.28	112.70	112.36	114.90	118.20	127.28	130.63	133.13	123.73	118.22
QF Idaho	55.51	54.61	54.42	54.54	54.92	56.52	55.69	56.57	56.49	55.93	55.84	66.61	55.33
QF Oregon	64.87	65.10	65.88	66.77	66.43	65.24	64.32	63.06	62.14	63.68	64.41	64.29	64.96
QF Utah	52.36	52.49	54.69	55.98	53.27	49.73	50.38	50.53	49.56	51.29	52.76	55.93	53.62
QF Washington	147.06	147.18	148.12	147.48	148.86	145.35	146.17	146.29	147.14	147.42	147.75	147.49	148.21
QF Wyoming	63.67	98.63	98.86	97.36	68.21	60.06	60.76	60.36	60.48	61.30	64.58	98.05	97.70
Biomass	157.11	156.76	158.70	156.78	157.38	156.75	157.36	156.76	156.76	157.36	156.76	157.36	166.76
Douglas County Forest Products QF	40.15	47.39	44.17	36.90	38.79	32.04	31.21	48.32	-	-	-	-	-
Evergreen BioPower QF	53.25	52.82	53.45	53.65	53.59	52.65	53.59	53.31	53.18	53.20	53.19	53.20	53.03
ExxonMobil QF	48.65	62.25	59.38	49.53	34.49	26.53	30.56	52.70	55.00	44.64	44.84	49.21	58.02
Kennecott QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	55.64	60.59	58.11	52.68	47.72	49.07	50.79	63.02	65.50	57.89	52.42	52.83	57.54
Mountain Wind 2 QF	64.32	68.54	64.99	60.89	53.80	54.64	64.17	86.20	82.08	68.28	57.35	60.13	65.11
Oregon Wind Farm QF	64.14	64.80	64.81	64.86	64.61	63.80	64.06	63.46	63.27	63.63	64.06	64.75	65.46
Simplot Phosphates	50.99	50.84	51.68	50.64	51.10	50.84	51.10	50.64	50.84	51.10	50.84	51.10	50.84
Spanish Fork Wind 2 QF	53.06	54.88	52.33	50.02	46.09	45.01	50.80	69.62	61.13	54.12	49.34	50.53	53.59
Sunnyside	64.02	60.38	62.68	60.68	61.16	60.31	62.02	62.88	64.87	63.21	70.46	63.99	64.30
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Weyerhaeuser QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	67.83	70.37	70.74	69.14	64.47	62.65	63.91	73.72	71.66	67.15	66.67	65.01	69.31
Mid-Columbia Contracts													
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach	12.96	10.38	14.38	14.68	11.88	10.40	10.07	10.58	14.05	20.46	17.33	16.33	13.37
Douglas - Wells	19.06	15.36	21.49	22.13	17.07	14.33	14.75	15.25	20.57	30.94	26.26	23.26	20.20
Grant Displacement	27.59	29.86	30.50	28.49	26.79	22.32	19.39	25.17	29.03	30.82	31.34	33.47	34.85
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	20.14	12.04	20.96	21.54	21.17	19.96	18.36	18.39	23.16	29.86	25.33	22.31	19.48
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	7.88	5.72	6.64	7.12	8.34	7.40	5.83	7.74	8.04	10.18	9.69	9.81	9.82
Total Long Term Firm Purchases													
COB	69.25	69.25	69.25	69.25	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	75.46	-	-	-	-	-	-	75.90	75.90	74.28	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	41.36	40.83	41.36	41.80	41.46	40.83	41.46	41.17	41.17	41.11	41.84	41.81	41.64
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	(86.57)	(382.53)	(446.11)	(526.45)	(597.31)	(698.22)	(679.32)	38.78	45.33	21.58	(176.77)	(181.44)	(144.90)
System Balancing Purchases													
COB	48.69	45.78	41.48	38.38	41.91	33.65	34.49	63.92	70.55	-	50.00	46.46	47.40
Four Corners	37.63	38.20	34.74	32.56	33.33	32.64	34.36	59.64	48.07	43.78	41.59	41.98	41.79
Mid Columbia	36.89	45.37	44.91	39.20	38.27	29.42	30.24	37.49	47.55	47.82	51.62	46.90	50.93
Mona	46.29	34.66	40.55	33.98	32.58	31.68	40.96	58.15	62.84	38.66	42.36	44.73	44.59
Palo Verde	36.88	38.30	37.83	36.51	33.89	31.46	24.52	38.25	37.21	39.04	37.80	37.84	37.04
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	42.24	-	-	43.88	43.63	35.64	25.66	-	-	-	-	-	-
Total System Balancing Purchases	39.68	39.62	39.28	35.15	36.31	30.33	32.49	64.13	55.78	43.67	41.20	41.39	43.77

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Thermal Resources													
Blundell	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01
Carbon	16.88	16.80	16.84	16.85	16.81	16.89	16.94	16.90	16.89	16.91	16.81	17.07	16.83
Cholla	19.21	19.20	19.21	19.21	19.21	19.22	19.22	19.21	19.20	19.21	19.21	19.21	19.21
Colstrip	11.18	11.18	11.18	11.18	11.18	11.18	11.18	11.18	11.18	11.17	11.19	11.18	11.18
Craig	15.34	15.34	15.34	15.35	15.34	15.35	15.36	15.35	15.34	15.35	15.36	15.34	15.34
Dave Johnston	8.92	8.92	8.92	8.91	8.91	8.92	8.92	8.92	8.92	8.92	8.92	8.91	8.91
Hayden	17.81	17.81	17.81	17.83	17.81	17.81	17.81	17.81	17.81	17.81	17.81	17.81	17.81
Hunter	14.02	13.99	14.00	13.99	14.02	14.07	14.08	14.03	14.02	14.03	14.05	14.01	13.99
Huntington	14.52	14.52	14.52	14.52	14.61	14.52	14.53	14.52	14.52	14.52	14.53	14.52	14.52
Jim Bridger	17.83	17.63	17.64	17.63	17.84	17.64	17.63	17.63	17.63	17.63	17.63	17.63	17.63
Naughton	15.16	15.16	15.16	15.19	15.16	15.17	15.19	15.19	15.19	15.19	15.18	15.18	15.16
Wyodak	9.14	9.13	9.13	9.13	9.13	9.14	9.15	9.17	9.16	9.15	9.14	9.13	9.13
Total Coal Expenses	14.57	14.58	14.57	14.40	14.38	14.40	14.60	14.61	14.80	14.86	14.82	14.62	14.57
Chehalis	43.27	45.60	-	-	-	-	-	39.61	40.47	40.92	41.69	49.62	52.53
Current Creek	38.78	39.33	39.53	38.56	36.05	36.59	36.65	37.28	37.95	38.24	37.53	42.04	46.63
Gadsby	65.13	-	-	-	-	-	-	64.48	64.91	66.42	-	-	-
Gadsby CT	72.90	79.14	78.39	-	-	-	74.68	65.04	65.66	69.80	72.96	84.66	93.99
Hermiston	35.73	33.70	34.51	33.87	39.02	7,931.32	-	34.13	34.10	34.20	34.03	35.37	35.31
Lake Side	36.75	37.19	37.26	36.64	33.66	34.45	36.02	35.49	35.98	36.43	36.94	39.67	44.53
Little Mountain	90.10	69.27	69.56	67.56	62.11	63.42	-	91.42	90.78	-	88.47	95.53	106.01
Total Thermal Resources	54.03	54.16	56.74	56.32	57.16	69.64	64.83	52.83	50.96	50.69	46.99	53.46	54.89

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ORDER NO. 09-432

Docket UE 207

STIPULATION OF JOINT PARTIES

Exhibit C

Rate Calculation

September 25, 2009

Exhibit C

UE 207 STIPULATION
PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF TAM ADJUSTMENT FOR JANUARY 1, 2010
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	Sch No.	kWh[1]	January 1, 2010 Sch 200 Present Revenue	Stipulated TAM Adjustment: Net Power Cost Increase Revenue	Stipulated TAM Adjustment: Final Upate[2] Revenue	Stipulated TAM Adjustment: Growth/ Loss Adjustment Revenue	Total Adjustment: Revenue	Total Adjustment: Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (5)+(6)+(7)	(9) (8)/(3)
	Residential								
1	Residential	4	5,435,845,633	$226,599,972	($4,403,546)	$0	$6,090,764	$1,687,218	0.031
2	**Total Residential**		5,435,845,633	$226,599,972	($4,403,546)	$0	$6,090,764	$1,687,218	
	Commercial & Industrial								
3	Gen. Svc. < 31 kW	23	1,013,940,497	$42,927,417	($834,214)	$0	$1,153,843	$319,629	0.032
4	Gen. Svc. 31 - 200 kW	28	2,045,065,385	$84,830,155	($1,648,515)	$0	$2,280,144	$631,628	0.031
5	Gen. Svc. 201 - 999 kW	30	1,378,646,160	$55,560,675	($1,079,718)	$0	$1,493,411	$413,694	0.030
6	Large General Service >= 1,000 kW	48	2,643,901,271	$99,835,377	($1,940,113)	$0	$2,683,468	$743,354	0.028
7	Partial Req. Svc. >= 1,000 kW	47	565,102,620	$20,957,166	($407,263)	$0	$563,306	$156,043	0.028
8	Agricultural Pumping Service	41	136,791,880	$5,648,605	($109,770)	$0	$151,828	$42,058	0.031
9	**Total Commercial & Industrial**		7,783,447,813	$309,759,395	($6,019,593)	$0	$8,326,000	$2,306,407	
	Lighting								
10	Outdoor Area Lighting Service	15	10,467,219	$238,234	($4,630)	$0	$6,403	$1,774	0.017
11	Street Lighting Service	50	10,738,031	$203,271	($3,950)	$0	$5,464	$1,514	0.014
12	Street Lighting Service HPS	51	16,084,697	$480,611	($9,340)	$0	$12,918	$3,579	0.022
13	Street Lighting Service	52	1,185,726	$27,141	($527)	$0	$730	$202	0.017
14	Street Lighting Service	53	9,316,113	$91,112	($1,771)	$0	$2,449	$678	0.007
15	Recreational Field Lighting	54	815,719	$13,729	($267)	$0	$369	$102	0.013
16	**Total Public Street Lighting**		48,607,505	$1,054,098	($20,484)		$28,333	$7,849	
17	**Total Sales to Ultimate Consumers**		13,267,900,951	$537,413,465	($10,443,624)	$0	$14,445,097	$4,001,474	
18	**Employee Discount**			($197,897)	$3,846	$0	($5,319)	($1,474)	
19	**Total Sales with Employee Discount**		13,267,900,951	$537,215,568	($10,439,778)	$0	$14,439,778	$4,000,000	

[1] Excludes unscheduled energy

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ORDER NO. 09-432

**PUBLIC UTILITY COMMISSION
OF OREGON**

UE 420

PACIFICORP

PAC/1314

**Docket No. UE 296
Order No. 15-394**

September 1, 2023

ORDER NO. 15 394

ENTERED DEC 11 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of PACIFICORP, dba PACIFIC POWER, 2016 Transition Adjustment Mechanism	FINAL ORDER

DISPOSITION: APPLICATION GRANTED

I. INTRODUCTION

In Order No. 15-353, we granted PacifiCorp, dba Pacific Power's 2016 Transition Adjustment Mechanism (TAM) application in a preliminary order. In this order we describe more fully the parties' positions and the rationale for our decisions.

PacifiCorp's final update for its 2016 net power costs (NPC) shows Oregon-allocated power costs of $373.4 million. This results in an overall annual rate increase of approximately $9.4 million or 0.7 percent. This is approximately $3.0 million less than the forecast described in Order No. 15-353.

II. BACKGROUND

Order No. 15-353 describes the background of this filing, which we only briefly summarize here. PacifiCorp's TAM is an annual filing with the objective to forecast the actual NPC the company expects to incur during the test year (12 months ending December 2016) to account for changes in market conditions. It also identifies the proper amount for the transition adjustment for customers wishing to move to direct access service.[1]

The Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Noble Americas Energy Solutions LLC (Noble Solutions) intervened in this proceeding. All parties filed two rounds of testimony, prehearing memoranda, and two rounds of briefs. A hearing was held on August 25, 2015.

[1] Under OAR 860-038-0275, each electric company must announce by November 15 the prices to be charged for electricity services in the next calendar year. For a more thorough discussion of the TAM, *see e.g.*, Order No. 09-274 (adopting the TAM guidelines) (Jul 16, 2009); Order No. 09-432 (refining TAM guidelines) (Oct 30, 2009); Order No. 14-331 (2015 TAM update) (Oct 29, 2014).

III. DISCUSSION

A. Background

PacifiCorp's 2016 TAM increases NPC by $9.4 million or 0.7 percent, for $373.4 million in Oregon-allocated NPC. PacifiCorp states that its NPC increase is due to several changes in GRID[2] modeling, a decrease in wholesale power sales revenue driven by its system balancing modeling change and lower electricity prices in the forward market, and an increase in purchased power expense due to its system balancing modeling change and new qualifying facilities (QFs).

In Order No. 15-353, we concluded that PacifiCorp met its burden to establish that its 2016 TAM filing will result in rates that are fair, just and reasonable. We found that the company had justified the need for the modeling changes it proposed with evidence in the record that was not adequately rebutted by the parties. We accepted no adjustments suggested by intervenors or the three changes requested by Noble Solutions. We imposed a one-year moratorium on PacifiCorp changing the GRID model to allow parties adequate time to understand, review, and evaluate recent changes to the model.

We provide below additional discussion of the parties' arguments and the reasoning to support our decisions below.

B. GRID Modeling Changes

1. System Balancing Modeling Change

a. Parties' Positions

PacifiCorp's system balancing transactions occur when PacifiCorp buys hourly and daily power when it needs additional resources to balance demand and supply and sells hourly and daily power when it has excess power resources. PacifiCorp made two changes to its modeling of system balancing transactions. First, it included separate, adjusted prices for short-term purchases and sales in its forward price curves.[3] Second, it added additional balancing volumes.[4] The impact of these modeling changes is $8 million.

PacifiCorp explains that it made these changes because its analysis of short-term transactions at multiple trading hubs from July 2011 through June 2014 showed that "at every trading hub, and for both on and off peak purchases and sales, in nearly every month for 36 months, it has been the case that purchases tend to cost more per MWh than

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[2] GRID stands for Generation and Regulation Initiative Decision Tool. GRID is PacifiCorp's hourly production cost model that the company has used in its Oregon rate filings since 2002.
[3] *See* PAC/500, Dickman/21-22 (a step-by-step explanation of the calculation).
[4] PAC/100, Dickman/20 (PacifiCorp increased system balancing transaction volume by 28 percent to reflect incremental balancing volumes associated with using 25 MW block monthly and daily products, and closing its position with real-time hourly products).

average spot prices and sales tend to have occurred below the average monthly spot price* * *."[5] PacifiCorp adds that the systematic difference in prices occurs because short-term resource needs are largely determined by loads and wind generation, which are correlated with market prices. Purchases tend to occur during higher-priced periods and sales tend to occur during lower-priced periods.[6]

Staff, CUB, and ICNU oppose this modeling change. ICNU and CUB assert that the power cost forecast should use a forward price curve that represents an unbiased, median estimate for future spot prices. ICNU and CUB characterize the system balancing modeling change as extraneous GRID adders, or out of model adjustments. CUB states the purpose of the TAM is to forecast power costs on a weather-normalized basis, with weather-related variations addressed in the Power Cost Adjustment Mechanism (PCAM), and also accounted for in the company's return on equity. CUB also states that PacifiCorp's proposal will allow one bad hydro year (or other weather event) to lead to over-forecasting of system balancing purchases, and that historical averages are not appropriate for variables that are highly influenced by weather and hydro conditions. PacifiCorp responds that its multi-year rolling average is a common normalizing tool.

ICNU also believes PacifiCorp is including a bid-ask spread by proposing to model a higher price for purchases than for sales in the same market at the same time. ICNU requests we adopt an alternative spread between purchases and sales of $0.50/MWh, which would reduce NPC by $1.7 million, and also remove the market caps. PacifiCorp answers that its proposal is similar to past adjustments made by Idaho Power Company and Portland General Electric (PGE) to use separate purchase and sale pricing.[7] CUB distinguishes these cases, stating that Idaho Power is more hydro dependent than most utilities, and Idaho Power's adjustment used normalized prices for purchases and sales, not actual historical (non-normalized data). CUB states that PGE's proposal for super-peak pricing was reduced in the second partial stipulation, in response to parties' concerns that it was inconsistent with normalized forecasting.

ICNU also opposes the additional volumes that PacifiCorp seeks to add. ICNU believes a better way to address any finding that transactional volume is too low in GRID modeling would be to eliminate the market cap mechanism which presently constrains transactional volume in GRID. PacifiCorp replies that the issue of market caps was fully litigated in the 2013 TAM and approved because market caps prevent the GRID model from artificially increasing sales to illiquid market hubs. PacifiCorp asserts that removal of the market caps would overstate the company's short-term market sales.

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[5] PAC/200, Graves/8.

[6] PAC/507, Dickman/1 (showing that PacifiCorp's system balancing purchases were, on volume weighted average, $3.47/MWh over the market average price, and system balancing sales were $5.42 below the average market price).

[7] *In the Matter of Idaho Power Co. Request for General Rate Revision*, Docket No. UE 167, Order No. 05-871 at 17-18 (Jul 28, 2005) (allowing Idaho Power to use on-peak prices for purchases and off-peak prices for sales). We grant PacifiCorp's request to take official notice of the Idaho Power testimony in UE 167, Idaho Power/300, Peseau/17-19, pursuant to OAR 860-001-0460(1)(d). *In the Matter of Portland General Electric Co. 2015 Annual Power Cost Update Tariff*, Docket No. UE 208, Order No. 09-433 at 3 (Oct 30, 2009).

Staff recommends the Commission open an investigation to allow the parties more time to explore the company's proposed changes. Staff fundamentally agrees with PacifiCorp's goal of improving GRID's modeling of balancing transactions, but Staff could not understand and verify the price and volume adders proposed, due to their complexity and the time constraints of this docket.

b. Resolution

Based on the evidence in the record, we are persuaded that short-term power purchase prices systematically exceed short-term power sales prices.[8] We are also persuaded that PacifiCorp has offered a reasonable adjustment to its forward price curve to account for these expected price differences that will result in a more accurate estimate of net power costs.[9]

We concur with PacifiCorp that its historic GRID modeling understated volumes of transactions because it assumed the volumes of purchases and sales matched exact needs. PacifiCorp's proposal increases balancing transaction volumes to reflect that. Based on the evidence in the record, we accept PacifiCorp's adjustment to increase balancing transaction volumes to reflect that the company balances its system with hourly products and 25 megawatt (MW) block monthly and daily products.

We are not persuaded by the intervenors' arguments to reject or modify PacifiCorp's modeling changes. First, with regard to CUB's concern that this adjustment should be rejected because it is not normalized, we note that PacifiCorp's use of three years of data is sufficient to smooth out variations to generate a reasonable estimate of expected spot price differentials. Second, with regard to ICNU's proposal to remove market caps, we addressed that issue in a prior order and adhere to that reasoning to keep market caps in GRID.[10] Third, we reject ICNU's recommendation to adopt an alternative bid-ask spread adjustment, because we agree with PacifiCorp that the difference in prices for short-term purchases and sales is not a bid-ask spread.

Finally, we reject Staff's request to open an investigation to examine GRID changes. Parties have had sufficient time and opportunity to review and assess the proposal. At the same time, we encourage parties to examine this modeling change in more detail in the next TAM cycle. Again we reiterate that we impose a moratorium on GRID modeling changes in the 2017 cycle to provide time for Staff, parties, and the Commissioners to get a better understanding of the GRID modeling changes that have been made over the past few years.

[8] For the 36 months ended June 2014, PacifiCorp's short-term firm transactions with deliveries spanning less than one week increased NPC by an average of $7.1 million compared to the historical average market prices. PAC/100, Dickman/26.

[9] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 9 (Oct 29, 2012) ("Our goal is to appropriately value Pacific Power's resources and we support adjustments to the valuation model only when there is evidence of a flaw in the model.").

[10] Order No. 12-409 at 7-8 (concluding that some form of market caps continue to be needed in GRID).

2. *Regulating Reserves*

a. *Parties' Positions*

PacifiCorp proposes to reflect regulation reserve requirements for its balancing authority areas (BAAs) on an hourly basis instead of flat monthly amounts. PacifiCorp uses the results from its 2014 Wind Integration Study to set hourly regulation reserves based on the hourly wind and load forecast. The company estimated reserves using a 99.7 percent confidence interval level and assumed compliance with its current North American Electric Reliability Corporation (NERC) reliability standard (RBC/BAAL). This change increases NPC by $0.5 million, due to more hours when the reserves are higher than the monthly average.

ICNU argues that PacifiCorp's reserve estimate is unduly conservative and proposes a reduction in regulation reserves based on the company's past (CPS2) performance. ICNU states that the company averaged 65 percent confidence with the prior reliability standard, and expects PacifiCorp to operate at a lower interval in the future due to EIM participation. ICNU suggest a 90 percent predictive confidence interval as a compromise that would reduce NPC by $2.8 million. PacifiCorp states that ICNU's adjustment would slash the company's regulation reserves by one-third.

b. *Resolution*

Based on the evidence in the record, we accept PacifiCorp's regulation reserves estimate and reject ICNU's proposed adjustments. We find that the CPS2 score is not relevant for calculating the regulation reserves needed to comply with the RBC/BAAL standard.[11] PacifiCorp provided unrebutted evidence that ICNU's proposed reduction would result in insufficient regulation reserves at certain times that could force PacifiCorp to curtail load or violate the standard, depending on the deviation for the entire interconnection.[12] Further, the 99.7 percent confidence interval is consistent with the confidence intervals derived by Bonneville Power Administration (BPA) and BC Hydro in similar studies, and PacifiCorp's 2014 Technical Review Committee expressed no concern with the company's use of a 99.7 percent confidence interval to determine reserve levels.[13]

[11] PAC/500, Dickman/47-49 (CPS2 measured the number of violations, not the magnitude of the violation, and the new RBC/BAAL standard measures deviations relative to the impact on the interconnection as a whole). At hearing, ICNU explained that it disagrees with the wind integration study being structured around this standard, but we do not have enough evidence in this record to disregard the wind integration study. Tr. at 18 (Aug 25, 2015).

[12] PAC/500, Dickman/52 (ICNU's proposal would result in insufficient regulation resources in 10 percent of each month).

[13] *See In the Matter of PacifiCorp, dba Pacific Power's 2015 Integrated Resource Plan,* Docket No. LC 62 at Appendix H (Mar 31, 2015) (the independent committee commented favorably on PacifiCorp's discussion and justification for its 99.7 percent exceedance level, noting that it reflected the company's policy of 100 percent reserve compliance).

Finally, we also note that PacifiCorp's reliability analyses suggest that "the company may need to consider more regulation reserves, not less, to maintain compliance with the RBC/BAAL standard in the future."[14]

3. Forced Outage Modeling Adjustment

a. Parties' Positions

PacifiCorp proposes to model forced outages and de-rates for individual plants rather than apply a uniform de-rate factor to all plants for all operating hours. PacifiCorp's revised method does not require adjustments for heat rates or minimum operating levels.

ICNU and Staff ask that PacifiCorp continue to use its current methodology and that we move this issue to a generic docket. ICNU states that PacifiCorp's proposal will result in a pattern of frequent, short outages not representative of normalized operations. PacifiCorp replies that, in Order No. 10-414 we found that the methodology was imperfect and encouraged future refinements.

b. Resolution

Consistent with the method we set forth in our Order No. 10-414, PacifiCorp still uses a four-year average of actual outage events to forecast plant outage duration and adjusts the average for lengthy individual plant outages.[15] Based on the unrebutted evidence, we find PacifiCorp's revised method results in projected plant availability distribution that better aligns with historic plant operations.[16]

We encourage parties to explore the modeling adjustment in the next TAM proceedings.

4. Wind Modeling: Avian Compliance and PPA Modeling

a. Parties' Positions

PacifiCorp made two changes to its forecasts of generation output at its wind plants. First, it reduced the projected generation output at the Glenrock and Seven Mile Hill wind sites to reflect expected energy lost to comply with a court order to reduce the risk to eagles. Second, PacifiCorp forecasted output from its wind power purchase agreements (PPAs) based on 48 months of actual generation results (or a combination of actual results and generator forecasts if forty-eight months of information is not available).

ICNU counters that the company should use the same generation output assumptions for ratemaking that were originally used to justify the wind facilities and the PPAs. For the

[14] PAC/500, Dickman/52.
[15] *In the Matter of Public Utility Commission of Oregon Investigation into Forecasting Forced Outage Rates for Electric Generating Units,* Docket No. UM 1355, Order No. 10-414 at 7 (Oct 22, 2010).
[16] *See* PAC/100, Dickman/35, Figure 2.

avian protection, ICNU states that the Wyoming wind projects were controversial at the time they were built. For the PPAs, ICNU states that the pricing negotiated for these contracts was based upon an assumed level of generation.

b. Resolution

We agree with PacifiCorp that its proposed adjustments will yield more accurate wind generation forecasts. We reject ICNU's proposals on two grounds. First, PacifiCorp must comply with the court order for avian protection. Second, actual wind generation at the wind PPA sites has been lower than forecasted. Forty-eight months of actual operation is sufficient for deriving a reasonable forecast of expected wind generation at a site that is superior to the long-range forecasts provided by the project owners.

5. EIM Benefits

a. Parties' Positions

PacifiCorp proposes $1.3 million in EIM costs and approximately $3 million in EIM benefits on an Oregon-allocated basis.[17] PacifiCorp increased the EIM benefits to address intervenors' arguments over lack of summer data, new EIM participants in 2016, and reduced flexibility reserves due to the new participants.

PacifiCorp explains that the majority of the EIM benefits are due to the company exporting to the California Independent System Operator (CAISO), and are reflected in the NPC report as wholesale sales revenue ($7.5 million company-wide). EIM imports from CAISO are a reduction to purchased power expense ($1 million company-wide). The remaining benefits are due to reduced flexibility reserves because of the diversity of the combined load in a larger footprint ($1.54 million company-wide).

Staff and intervenors raise numerous objections to PacifiCorp's forecast of EIM benefits and propose adjustments. First, Staff and ICNU contend that PacifiCorp has under-forecasted EIM benefits. Staff argues that PacifiCorp should impute an additional $1.07 million in EIM dispatch benefits from the Idaho Power asset exchange, which increased the dynamic transfer capability between PacifiCorp's west and east BAAs from 200 MW to 400 MW. Staff explains that the company's marginal resources are located in the east balancing area and must be dynamically transferred to the west BAA before being exported to CAISO. PacifiCorp disagrees, stating that it will use the additional dynamic transfer capability for the balancing of its own resource (intra-regional transfers), which are already modeled in GRID. PacifiCorp also questions whether its coal-fired east-side resource will be dispatched in the EIM when its natural gas units have a similar marginal energy cost and when CAISO imports incur a greenhouse gas charge.

[17] PacifiCorp Prehearing Memorandum at 2 and 19 (Aug 17, 2015) states approximately $3 million in EIM benefits on an Oregon-allocated basis. This value is not used in testimony or exhibits. *See infra* n. 18.

ICNU asserts that PacifiCorp should have reduced reserves due to the increased dynamic transfer capability from the Idaho Power asset exchange. PacifiCorp disagrees, stating that there is no mechanism for sharing flexibility reserves under the EIM. PacifiCorp clarifies that it can transfer contingency reserves from one BAA to another, but the transfers must be scheduled in advance, and then the dynamic transfer capability is no longer available to the EIM.

Second, several parties raise concerns about the limited data PacifiCorp used to forecast the benefits. PacifiCorp responded with additional historical results, a proposal for EIM results through September 2015 via its final update, and provided greater weight to the June 2015 results to address seasonality concerns. Staff supports PacifiCorp's revised proposal. CUB recommends that we accept PacifiCorp's forecast and defer the difference between that forecast and the actual results for later ratemaking treatment. CUB explains that a deferral is appropriate with less than one year of data upon which to base a forecast. ICNU states that seven months of data requires some type of proxy be used to model EIM benefits and address seasonality, and recommends PacifiCorp model EIM benefits based on the market spreads between two trading hubs, which would reduce NPC by $0.4 million.

Finally, ICNU raised concerns about the benefits that might be provided by new EIM participants – NV Energy, Puget Sound Energy (PSE), and Arizona Public Service (APS). Although PacifiCorp included additional $0.4 million on an Oregon-allocated basis to account not only for NV Energy's full year of participation, but also for three months of PSE and APS participating, ICNU continues to assert that NPC should be reduced by an additional $0.8 million to account for the new entrants joining the EIM.

b. Resolution

We accept PacifiCorp's forecast of EIM benefits in the test period of $2.7 million on an Oregon-allocated basis, and reject the adjustments proposed by Staff and ICNU.[18] We find that, PacifiCorp's 2016 EIM benefits, net of EIM costs, are $1.41 million on an Oregon-allocated basis.

We reject Staff's recommendation to increase interregional EIM benefits based on the increased dynamic transfer capability between PacifiCorp's BAAs because there is insufficient evidence to support that adjustment. PacifiCorp has explained that interregional EIM exports are limited by several factors depending on timing, including available California Oregon Intertie (COI) capacity;[19] COI congestion in California;[20] and

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[18] EIM benefits are incorporated into the NPC report and not specifically listed in testimony, so we have applied Oregon's 25.464 percent allocation factor to the total-company figures in PAC/506, Dickman/1 ($9,104,990 in EIM exports and imports), PAC/100, Dickman/9 ($1.0 million in initial flexibility reserves savings), PAC/500, Dickman/13 and Dickman/43 ($213,000 in additional reserve savings for PSE and APS joining in October 2016 and $323,000 in additional reserve savings for NV Energy interconnecting with PacifiCorp's east balancing area) = $2.71 million in Oregon-allocated benefits. EIM costs are reported in PAC/505, Dickman/1 as $1.3 million on an Oregon-allocated basis.

[19] PAC/500, Dickman/56 ("The export benefit is also tied to the transmission capacity available for EIM transactions in each month of the forecast period.").

the economics of generating resources.[21] PacifiCorp has also explained that some of the increased dynamic transfer capability will go for intraregional transfers which are already modeled in GRID. Further, Staff's analysis fails to account for the greenhouse gas adders that would change what resources are economic to meet imbalance energy needs. Thus, we cannot conclude that additional transfer capability between PacifiCorp's BAAs will necessarily increase EIM benefits.

We reject ICNU's proposed adjustment to increase flexibility reserve savings due to the increased dynamic transfer capability between PacifiCorp's BAAs. PacifiCorp has explained that increased dynamic transfer capability will be used for intraregional EIM transfers and for contingency reserve transfers occurring outside of the EIM. PacifiCorp states, without rebuttal, that it cannot dynamically transfer flexibility reserves between BAAs.

We also reject ICNU's proposed seasonality adjustment to forecast interregional EIM benefits for the test period. We agree with PacifiCorp's assessment of the flaws in the proposed modeling adjustment. Based on the evidence in the record, we agree with PacifiCorp that the spread between market prices in Oregon and California is not representative of the benefits that will be achieved and that the assumption of identical export volumes is unwarranted.

We accept PacifiCorp's approach to incorporate benefit results through September 2015 and its methodology for generating estimates for the test year period months. We concur that this approach will yield reasonable estimates of interregional benefits.

We concur with PacifiCorp that ICNU's estimates of the incremental interregional EIM benefits due to NV Energy, PSE, and APS are unjustifiably and unreasonably high. The estimates are considerably higher than estimates generated in the separate studies prepared by the Energy and Environmental Economics used by PacifiCorp. Further, we agree that ICNU fails to account for diminishing returns from increased transfer capability and overstates the transmission capacity available to support transfers between PacifiCorp's east BAA and NV Energy's BAA.

C. Generation Portfolio: Hermiston PPA and Hermiston Transmission Contract

1. Parties' Positions

ICNU challenges PacifiCorp's decision not to renew the Hermiston PPA, as well as the company's earlier decision to renew the transmission contract associated with the PPA. This PPA is for the output of the 50 percent share of the plant that is not owned by the

[20] PAC/100, Dickman/13 ("During periods of transmission congestion on the COI, even if the company has economic resources and transmission available to the California-Oregon Border (COB), the CAISO may not be able to import EIM volumes.").

[21] PAC/100, Dickman/17 ("In other periods, the Company may not have sufficient resources that are economic at the CAISO market price to fill the entire available path.").

company. ICNU argues that PacifiCorp was imprudent in only considering its summer peaking needs in making the decision not to renew the PPA, noting that PacifiCorp's 2015 Integrated Resource Plan (IRP) stated that a winter peaking resource may be needed in the near-term. ICNU also contends that PacifiCorp was imprudent in renewing the PPA transmission agreement before analyzing whether it would extend the underlying PPA.

2. Resolution

We reject the recommendations by ICNU to find termination of the Hermiston PPA imprudent and disallow the costs of the point-to-point transmission that had served the plant. With regard to the decision to not renew the PPA, we find that PacifiCorp adequately evaluated its system peak needs and the resources needed to meet its peak needs in its IRP. Based on its evaluation, PacifiCorp concluded the Hermiston PPA was an expensive source of capacity and was not needed. In addition, the inclusion of the PPA will pose immediate costs to customers by increasing NPC by $3 million.

With regard to the transmission contract, PacifiCorp was contractually required to terminate or renew the transmission contract nine months before the renewal deadline for the Hermiston PPA. Further, PacifiCorp provides unrebutted evidence that the line will be used during the forecast period, and that contract renewal is worthwhile to maintain its rollover transmission rights. Accordingly, we find no basis to disallow costs.

D. Direct Access Adjustments

PacifiCorp's TAM is used to establish transition adjustment charges or credits that direct access customers must pay. The charge is the difference between net power costs in Schedule 201, and the estimated market value of the electricity that is freed up when a customer chooses direct access.[22]

1. Parties' Positions

Noble Solutions asks for three changes related to the direct access charge. First, Noble Solutions states that the transition credit for freed-up generation should include the value of Renewable Portfolio Standard (RPS) compliance, asserting that PacifiCorp's RPS compliance obligation is reduced for direct access departing load, thus freeing up renewable energy credits (RECs) that were previously acquired by PacifiCorp to serve that load. Noble Solutions states that, without a REC credit, direct access customers pay for RPS compliance twice, once from PacifiCorp and once from their Electricity Service Supplier (ESS). Because there is not a market index for the value of the RECs, Noble Solutions proposes using the average sales price of PacifiCorp's unstructured (or unbundled) RECs as a reasonable proxy price.

[22] *See* Order No. 13-387 at 10 (Oct 28, 2013); Order 12-409 at 14 (Oct 29, 2012).

PacifiCorp responds that the Commission requires the company to bank all RECs that are compliant with the RPS.[23] PacifiCorp states that it may not be able to sell RECs freed-up by departing direct access load, and that if a benefit did occur it is unnecessary to include that revenue as a transition credit because the revenue would be passed back to all customers through the property sales balancing account.[24]

Second, Noble Solutions challenges the escalation of the Schedule 200 opt-out charge in PacifiCorp's five-year opt-out program. Noble Solutions explains that the opt-out charge should be limited to the generation investment incurred prior to the sixth year. Noble Solutions states that once that portfolio is frozen, the revenue the company earns will decline each year as a portion of those assets is depreciated and amortized. Noble Solutions asks that the Schedule 200 entry decline 2.36 percent per year from years 6 through 10.

PacifiCorp responds that the consumer opt-out charge properly escalates the company's fixed generation costs at the average rate of inflation—so the fixed generation costs are held constant through year 10. PacifiCorp states that the Commission has already denied Noble Solutions' request to decrease the consumer opt-out charge in years 6 through 10 in docket UE 267,[25] and that Noble Solutions has not presented any new evidence or arguments.

Third, Noble Solutions seeks a change in the five-year opt-out program enrollment deadline. Currently, if a customer opts out, but does not submit its Direct Access Service Request (DASR) by the cutoff date, then the customer's opt-out election reverts to the one-year program. Noble Solutions states that this approach is different than the one and three year program policies and is unjustified. Noble Solutions states that the customer with the late DASR should have the option to enter the five-year program late by paying PacifiCorp all applicable five-year opt-out charges that would have applied to the customer with a timely DASR. PacifiCorp states that the company's five-year opt-out program is treated differently than the one-year and three-year program because customers pay transition adjustments for the five-year program and are then no longer subject to transition adjustments, and a late DASR would pay less than the full five years of transition adjustments.

Regarding the deadline to submit a DASR, PacifiCorp had stated that, if the Commission does allow leeway with the deadline, then the customer should pay the difference between the one-year and three-year programs and the five-year program; that service from the ESS begin no later than February 1; and that the company receives the completed DASR from the ESS no later than 13 days before the commencement of service from the ESS. Noble Solutions agreed to this proposal, but PacifiCorp maintained that its deadline policy should not be changed.

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[23] PacifiCorp Prehearing Memorandum at 31 (citing *In the Matter of PacifiCorp, dba Pacific Power, Application for Sale of Renewable Energy Credits,* Docket No. UP 266, Order No. 11-512 (Dec 20, 2011)).
[24] PacifiCorp Prehearing Memorandum at 31 (citing PAC/500, Dickman/84).
[25] PacifiCorp Prehearing Memorandum at 32 (citing *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-195 at 2 (Jun 16, 2015)).

2. *Resolution*

We reject all of Noble Solutions' proposed changes. Noble Solutions' formula for valuing freed-up RECs assumes PacifiCorp will sell its RECs. As PacifiCorp points out, today and for the foreseeable future, PacifiCorp will be banking RECs. Further, PacifiCorp states if the RECs are sold in the future, departing direct access customers will receive a share of the revenues from sales. At best, the net present value of the value of any freed-up RECs is *de minimis.*

We have previously addressed the claim that the customer opt-out charge should be reduced to reflect a more accurate estimate of fixed generation costs. Noble Solutions has produced no new evidence or argument to persuade us to change our positon. PacifiCorp explains that incremental generation is not added after year five.[26] PacifiCorp also explains that, in real (inflation-adjusted) terms, the fixed generation costs are held constant through year 10. As we did in previous orders, we find it reasonable to assume that fixed generation costs will increase at the rate of inflation after year five.

Finally, the four-week time period allowed is ample time for the ESSs to file direct access requests.[27] We find no compelling reason to allow for late requests, and the record does not show customers struggling to submit DASRs in the December time period under the current one-year and three-year programs.[28]

IV. ORDER

IT IS ORDERED THAT:

1. Advice No. 15-005 is permanently suspended.

2. PacifiCorp, dba Pacific Power, shall update its net power costs (NPC) to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism NPC for the calendar year 2016, filing tariffs to be effective January 1, 2016.

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[26] Noble Solutions/100, Higgins/23.
[27] PAC/800, Ridenour/4.
[28] Noble Solutions/105, Higgins/5. In the last six years, there have been three DASRs that did not allow the ESS to begin service on January 1, and these three DASRs were submitted in the months of March and May, for the one-year program (under the one-year and three-year opt-out program the consumer is moved to one-year direct access service 13 business days after the DASR is received due to the ongoing nature of the transition adjustments under the program).

3. PacifiCorp, dba Pacific Power, will make no changes to its GRID modeling for its 2017 TAM, and is directed to work with parties and the Commission to allow thorough review and evaluation of recent GRID model changes.

Made, entered, and effective DEC 11 2015.

Susan K. Ackerman Chair	**John Savage** Commissioner

Commissioner Bloom concurring:

I support today's order but write separately to set forth my concern that this TAM proceeding, with PacifiCorp's numerous proposed changes to GRID, left the parties and this Commission little time to evaluate and verify the assertions made by PacifiCorp. The complexity of PacifiCorp's TAM filings and GRID adjustments has been a recurring theme—one raised by both the parties and the Commission.[29] I acknowledge PacifiCorp's attempts to explain the workings of GRID to parties at various workshops. Despite these efforts, however, many stakeholders appear to be lacking the necessary understanding of the model that would allow them to sufficiently comprehend proposed modeling changes and respond to them as necessary in a compressed TAM proceeding.

The difficulty of understanding GRID is exacerbated by PacifiCorp's continual adjustments to it. For example, the system balancing change adopted in this order adds another layer of complexity to the company's forward price curve and hourly scalars that we adopted not long ago in the 2012 TAM. Similarly, the forced outage modeling change adds more detail and cost to the previous "haircut" method that PacifiCorp adopted following our directives in docket UM 1355. I signed the order today because I believe that the company has shown that these refinements and new adjustments will produce a more accurate GRID forecast. However, I remain concerned that the parties had little time to catch-up and understand recent GRID adjustments before PacifiCorp proposed a new layer of adjustments here. Moreover, although these significant changes deserved close scrutiny, they needed to compete for attention as the parties focused on other NPC items and a disputed EIM benefit forecast.

[29] *See e.g., In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism,* Docket No. UE 227, Order No. 11-435 at 21 ("We initially observe, as a general matter, that a stand-alone TAM is intended to be a streamlined proceeding. Review and verification of the company's complex modeling presents a serious challenge, particularly in the context of a stand-alone TAM proceeding, when the Commission is presented with limited information and a short timeframe for decision.").

To give the parties additional time to understand GRID and the various adjustments adopted in this and prior proceedings, we have imposed a one year moratorium on PacifiCorp making further changes to the model. During this moratorium, I ask PacifiCorp to renew and increase its efforts to explain GRID to the parties with the hope of resolving some of the recurring GRID questions, such as short-term transactions and outage modeling. I would also request a Commissioner workshop once the parties have had time to work together.

PUBLIC UTILITY COMMISSION OF OREGON

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 420

PACIFICORP

PAC/1315

Docket UE 421 Staff/100
Opening Testimony of Curtis Dlouhy, Julie Jent, Anna Kim, and Rose Pileggi

September 1, 2023

CASE: UE 421
WITNESS: Curtis Dlouhy Ph.D., Julie Jent, Anna Kim, Rose Pileggi

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

August 31, 2023

Q. Please state your name, occupation, and business address.

A. My name is Curtis Dlouhy, Ph.D. I am an Economist employed in the Utility Strategy and Integration Division of the Oregon Public Utility Commission (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/101.

Q. Please state your name, occupation, and business address.

A. My name is Julie Jent. I am a Senior Utility Analyst employed in the Energy Costs Section of the Rates, Safety, and Utility Performance (RSUP) Program of the OPUC. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/102.

Q. Please state your name, occupation, and business address.

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the RSUP Program of the OPUC. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/103.

Q. Please state your name, occupation, and business address.

A. My name is Rose Pileggi. I am a Senior Utility Analyst employed in the Energy Costs Section of the RSUP Program of the OPUC. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/104.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide an overview of the Company's Power Cost Adjustment Mechanism (PCAM) filing and an overview of Staff's analysis to date.

Q. Did you prepare any exhibits for this docket?

A. Yes. We prepared Exhibit Staff/101, Exhibit Staff/102, Exhibit Staff/103, and Exhibit Staff/104.

Q. How is your testimony organized?

A. Our testimony provides an overview of the 2022 PCAM filing and discusses Staff's analysis of PacifiCorp's request to amortize more than $130 million of excess Net Variable Power Costs incurred during 2022.

OVERVIEW OF 2022 PCAM FILING

Q. What is the PCAM?

A. The PCAM is a true-up proceeding for net variable power costs (NVPC) that compares PacifiCorp's actual NVPC incurred in operations against the forecast NVPC set in rates annually in PacifiCorp's Transition Adjustment Mechanism (TAM) proceeding. The PCAM is the mechanism by which PacifiCorp recovers or refunds the difference between actual power costs and forecast power costs after applying a deadband, sharing mechanism, earnings test, and amortization cap.

Q. Where was the 2022 NVPC forecast identified?

A. The forecast for power costs in the 2022 calendar year was adopted in the 2022 TAM through Order No. 21-379 in Docket No. UE 390.

Q. Please outline major activities in the procedural history of this docket.

A. The Company filed the PCAM on May 15, 2023.

On August 3, 2023, in lieu of a settlement conference, the Company provided a workshop on workpapers and other data that had been filed by the Company.

On August 18, 2023, the Company provided a workshop at Staff's request that covered basic coal operations and major coal market factors that affected the Company in 2022.

Q. Please provide an overview of Staff's testimony.

A. In Opening Testimony, Staff provides context to the ongoing review of costs associated with the PCAM and provides analysis of rate impacts from the PCAM.

Q. What issues are addressed in Staff's testimony?

A. In Staff/100, we provide an overview of the filing and some of our analysis to date. In Staff/200, witness Bret Stevens addresses the rate impact of the PCAM on Oregon customers.

Q. Please summarize PacifiCorp's 2022 PCAM filing.

A. In the 2022 PCAM, the Company seeks to recover the difference between actual net power costs incurred and the base costs established in the 2022 TAM filing in UE 390. Actual PCAM costs on an Oregon basis are $163.3 million more than in the 2022 TAM. The Company seeks to recover $131.1 million of these costs amortized over two years.[1]

Q. What is the total impact of the PCAM?

A. In the 2022 PCAM, the Company seeks to recover $131.1 million on an Oregon-allocated basis for the 2022 PCAM. This number was calculated by applying the deadband, sharing band, and earnings test to the power cost variance (PCV).[2] The Company proposes amortizing these costs over two years starting January 1, 2024, with an impact of $69 million a year.[3]

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1 PAC/100, Painter/2.
2 PAC/100, Painter/2.
3 PAC/100, Painter/4.

Q. Did Staff review PacifiCorp earnings for 2022?

A. Yes. In Staff's review of PacifiCorp's Results of Operations, PacifiCorp's Type 1 return on equity earnings for 2022 was 2.84 percent. This is well below PacifiCorp's authorized return on equity of 9.5 percent. Therefore, there is no reduction in the amount of power costs that is recoverable by PacifiCorp with respect to an earnings test.

Q. What is the effect of the increase on Oregon customers?

A. The proposed amortization would result in a roughly four percent increase in rates in 2024 and 2025 above 2023 levels. The impact varies by customer type and will be addressed further in Staff/200.[4] These rates will go into effect on January 1, 2024, at the same time as rates from the 2024 TAM, which will have an additional impact on customer rates.

Q. Please list changes by individual cost categories since last year's filing.

A. On a company-wide basis, compared to the 2022 TAM, coal fuel expenses decreased by $66 million, natural gas expenses increased by $307 million, purchased power expenses increased by $65 million, and the cost associated with reduced wholesale sales revenue increased by $322 million. In total, Company-wide NVPC were $667 million higher than the 2022 TAM forecast.[5]

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4 PAC/100, Painter/12.
5 PAC/100, Painter/12.

Q. What are the major factors the Company cites that have contributed to this increase?

A. The Company references the following factors that have increased costs beyond what was forecasted:

- Extreme weather events, such as heat waves and the ongoing drought in the summer months;
- The war in Ukraine;
- Decreased coal generation due to coal supply shortages; and
- An increase in natural gas generation to compensate for reduced coal generation.

Despite higher fuel prices, increased natural gas generation was less expensive than additional market purchases. The Company attributes the difference in forecast and actual market sales due to modeling of market depth and the increase in market purchase costs due to heat waves.[6]

Q. Does Staff have additional questions related to PAC's operations?

A. Yes. Based on events in 2022 referenced by the Company, Staff understands why the Company might choose to dispatch less coal and more natural gas, and that market purchases and sales were less favorable overall than forecast. However, we have questions about the Company's decisions regarding which coal plants were dispatched and which gas plants were dispatched. It is unclear to Staff why the Company chose to increase

[6] PAC/100, Painter/13-17.

generation at some facilities and decrease generation at others. Staff also questions why the Company attributes the difference in wholesale revenues to modeling assumptions rather than having less energy to sell due to reduced generation of lower cost coal units. Staff plans to investigate these topics further and wishes to continue meeting with PAC to understand these topics better.

Q. Please describe Staff's experience investigating the impact of coal markets and coal availability on PacifiCorp's power costs.

A. The coal market is complex. Interactions of various factors in the market, and how the Company responds to these interactions on a unit-by-unit basis, impact the Company's NVPC. In Staff's experience, the current discovery process is not an adequate vehicle for Staff and parties to gather sufficient information about the complex interactions of the coal market and the Company's actions in order to validate or contest the Company's forecast of coal-related costs. The workshop held by the Company on August 18 was particularly helpful in understanding the challenges the Company faced with coal markets in 2022.

Q. Why does Staff find it important to have more information on the coal market and coal generation?

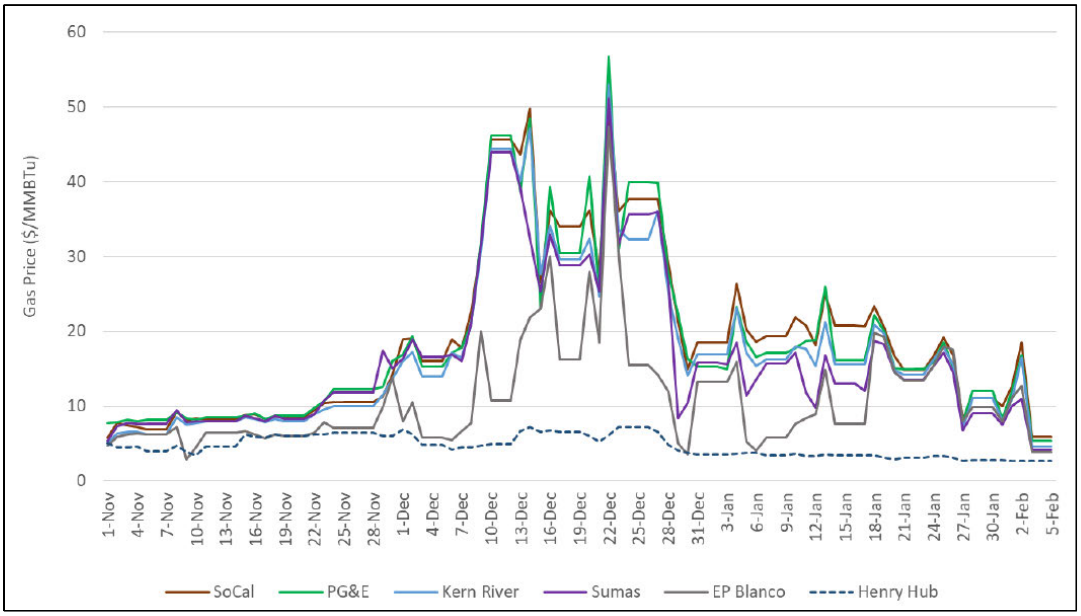
A. Staff believes that the coal market is less stable now than in the past and the market has experienced several shocks recently. As the energy economy shifts toward generation that requires lower carbon intensity, the future for coal is less certain even when the Company is still relying on a steady supply of coal to meet load. Staff believes it is important to understand the impacts of coal market changes on the Company's complex system. Each facility may be facing different impacts and it is difficult to understand these decisions without more information about the interactive effects.

Q. Please describe Staff's understanding of the natural gas market in 2022.

A. Staff is aware that gas prices have stayed above $5/MMBtu since mid-2021, but in late 2022, prices sustained at even higher than normal seasonal levels. Next-day natural gas prices for Western hubs reached a maximum value of about $57/MMBtu in December 2022. In addition, next-day and future bilateral power prices experienced price spikes during December 2022 between $400/MWh and $500/MWh. As a result of this, CAISO electricity prices increased fivefold, at an average price of more than $250/MWh. See Figure 1 below for a sampling of gas prices at different Western hubs in 2022.[7]

[7] 2022-Fourth-Quarter-Report-on-Market-Issues-and-Performance-Mar-16-2023.pdf (caiso.com).

FIGURE 1: GAS PRICES AT WESTERN HUBS IN 2022[8]



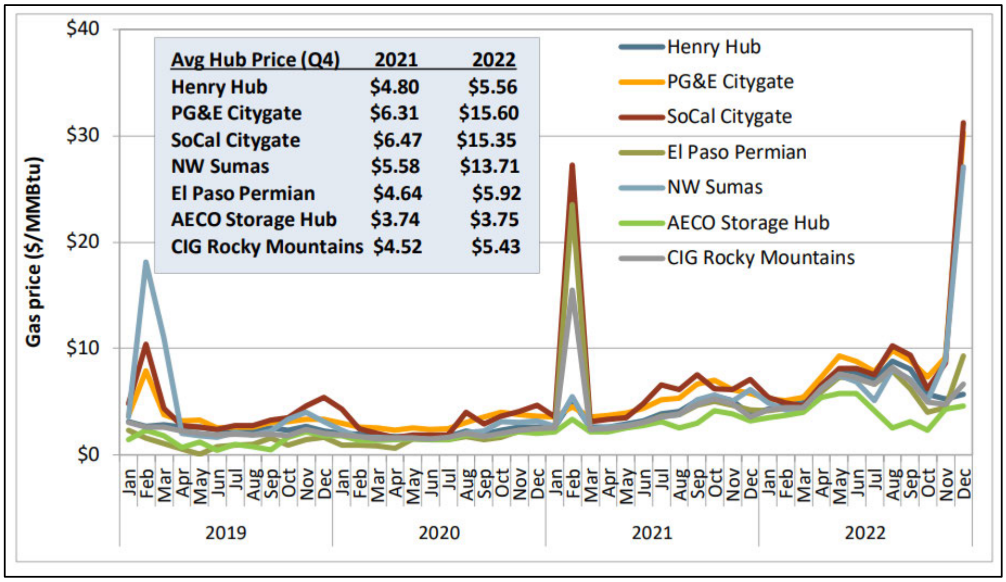
Q. Could PacifiCorp have anticipated the large increase in natural gas prices in 2022?

A. Staff does not believe so. As previously stated, natural gas expenses increased by $307 million. While the Company could have predicted higher than average monthly prices during the heating season of each year, this would have impacted physical gas bought in the market but not necessarily gas in storage or gas swaps. As seen in Figure 2, natural gas prices follow a cyclical pattern that mirrors the heating season. For PacifiCorp, much of the increase in its total natural gas costs appear to be from a change in

8 See Gas Conditions and CAISO Markets Report published on February 6, 2023 and prepared by Market Analysis.

expectation for natural gas at the generating facilities that PacifiCorp either owns or contracts rather than Gas physicals, swaps, or storage.

FIGURE 2: AVERAGE MONTHLY NATURAL GAS PRICES BY HUB



Q. Has Staff proposed any adjustments?

A. Not at this time, but Staff's investigation into the over $130 million in excess NVPC is ongoing. Staff may have adjustments as its investigation evolves.

Q. Does Staff have recommendations for the Commission at this time?

A. No. Staff continues to research the above topics and related impacts to better understand the Company's system and decision processes.

Q. Does this conclude your testimony?

A. Yes.