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KATHERINE MCDOWELL
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August 23, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 390 – *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp d/b/a Pacific Power's Exhibit List and Cross-Examination Exhibits. Confidential material in support of the filing will be provided to qualified parties under Protective Order No. 16-128 via encrypted zip file.

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 pages of PacifiCorp's **Exhibit List and Cross-Examination Exhibits** on the parties listed below that have signed the protective order via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 390

AWEC	
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MOYA ENRIGHT **(C) (HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97301 moya.enright@state.or.us	

Dated this 23rd day of August, 2021.

/s/ Alisha Till

Alisha Till
Paralegal
McDowell Rackner Gibson PC

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 390

In the Matter of PACIFICORP dba PACIFIC POWER, 2022 Transition Adjustment Mechanism.	**PACIFICORP'S EXHIBIT LIST AND CROSS-EXAMINATION EXHIBITS**

PREFILED EXHIBITS

* Exhibits adopted in their entirety by another witness are listed under the adopting witness.

Douglas R. Staples, Net Power Cost Advisor	
PAC/100	*(Adopted) CONFIDENTIAL Direct Testimony of David G. Webb
PAC/101	*(Adopted) Oregon-Allocated Net Power Costs
PAC/102	*(Adopted) Net Power Costs Report
PAC/103	*(Adopted) CONFIDENTIAL Update to Renewable Energy Production Tax Credits
PAC/104	*(Adopted) Step Log Change
PAC/105	*(Adopted) March 1, 2021 Notice Letter
PAC/106	*(Adopted) List of Expected or Known Contract Updates
PAC/107	*(Adopted) CONFIDENTIAL Economic Coal Cycling Study
PAC/400	CONFIDENTIAL Reply Testimony of Douglas R. Staples (Revised by Errata filing 8/19/21)
PAC/401	2022 TAM Oregon-Allocated Net Power Costs Reply Filing
PAC/402	2022 Results of Updated Net Power Cost Study Reply Filing
PAC/403	2022 Updates Summary Reply Filing
PAC/1000	CONFIDENTIAL Surrebuttal Testimony of Douglas R. Staples (Revised by Errata filing 8/19/21)
Dana M. Ralston, Senior Vice President of Thermal Generation and Mining	
PAC/200	CONFIDENTIAL Direct Testimony of Dana M. Ralston
PAC/600	CONFIDENTIAL Reply Testimony of Dana M. Ralston
PAC/601	CONFIDENTIAL 1st Revised Response to OPUC Data Request 71
PAC/602	CONFIDENTIAL 1st Supplemental Response to OPUC Data Request 154
PAC/1200	CONFIDENTIAL Surrebuttal Testimony of Dana M. Ralston
Robert M. Meredith, Director, Pricing/Cost of Service	
PAC/300	*(Adopted) Direct Testimony of Judith M. Ridenour

PAC/301	*(Adopted) Proposed TAM Rate Spread and Rates
PAC/302	*(Adopted) Proposed Tariff Schedule
PAC/303	*(Adopted) Estimated Effect of Proposed TAM Price Change
PAC/900	Reply Testimony of Robert M. Meredith
PAC/1500	Surrebuttal Testimony of Robert M. Meredith
Seth Schwartz, President, Energy Ventures Analysis, Inc.	
PAC/500	CONFIDENTIAL Reply Testimony of Seth Schwartz
PAC/501	Seth Schwartz' Resume
PAC/502	PacifiCorp Data Request 1.7
PAC/1300	Surrebuttal Testimony of Seth Schwartz
Daniel J. MacNeil, Commercial Analytics Adviser	
PAC/700	CONFIDENTIAL Reply Testimony of Daniel J. MacNeil
Mary M. Wiencke, Vice President of Market, Regulation, and Transmission Policy	
PAC/800	CONFIDENTIAL Reply Testimony of Mary M. Wiencke
PAC/1400	Surrebuttal Testimony of Mary M. Wiencke
Michael G. Wilding, Vice President, Energy Supply Management	
PAC/1100	Surrebuttal Testimony of Michael G. Wilding
PAC/1101	PacifiCorp's Response to OPUC Data Request 135 and 136

CROSS-EXAMINATION EXHIBITS

Exhibit PAC/1600 Staff Responses to PacifiCorp Data Requests

Exhibit PAC/1601 (Confidential) Excerpts from PacifiCorp's Workpapers

Exhibit PAC/1602 Docket No. UE 374 Excerpt from Order No. 20-473

Exhibit PAC/1603 Docket No. UE 374 Excerpt from Staff/2400 Rebuttal Testimony of Scott Gibbens[1]

Exhibit PAC/1604 Docket No. UE 344 Order No. 18-449

Exhibit PAC/1605 Docket No. UE 361 Order No. 19-415

Exhibit PAC/1606 Docket No. UE 379 Order No. 20-489

Exhibit PAC/1607 Docket No. UE 392 Letter and excerpt from PAC/100 Direct Testimony of Jack Painter

[1] The figures included in the excerpt from Staff/2400 were originally designated confidential in docket UE 374 because the underlying information Staff used to develop the figures was designated by PacifiCorp as confidential. PacifiCorp hereby waives the confidential designation for the figures included in the excerpt of Staff/2400, although the underlying information remains confidential.

Exhibit PAC/1608	Docket No. UE 375 AWEC/100 Opening Testimony of Bradley G. Mullins
Exhibit PAC/1609	Docket No. UE 216 Order No. 10-363
Exhibit PAC/1610	Docket No. UE 216 Joint Testimony in Support of Stipulation
Exhibit PAC/1611	Docket No. UE 374 Excerpt from AWEC/100 Opening Testimony of Bradley G. Mullins
Exhibit PAC/1612	Docket No. UE 374 Excerpt from AWEC/500 Rebuttal Testimony of Lance D. Kaufman

DATED: August 23, 2021

MCDOWELL RACKNER GIBSON PC

Katherine McDowell
Adam Lowney

Attorneys for PacifiCorp d/b/a Pacific Power

PUBLIC UTILITY COMMISSION
OF OREGON

UE 390

PACIFICORP

PAC/1600

Staff Responses to PacifiCorp Data Requests

August 23, 2021

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 01.

Data Request No 01:

01. Refer to Staff/1400, Anderson/10, lines 5-7, where Staff testifies: "A full assessment of economic cycling on PacifiCorp's system as a whole is needed before PacifiCorp signs its coal supply agreements." Please describe in detail how PacifiCorp should conduct the "full assessment" Staff recommends. Specifically, please identify:

    a. the specific modeling Staff recommends;

    b. whether PacifiCorp should assume that all coal units are allowed to economically cycle without restriction or just the plant for which the Company is negotiating a coal supply agreement;

    c. whether there should be any restrictions on the ability of coal units to economically cycle and, if so, what those restrictions should be;

    d. how existing coal supply agreements and their associated minimum take provisions should be modeled; and

    e. any other modeling specifications or methodologies Staff believes must be considered as part of the "full assessment" it recommends.

Staff Response No 01:

01. There is likely more than one way that economic cycling could be studied effectively. The most important goals of any initial study would be to identify the best candidates for economic cycling, in order to inform further study and discussion with any co-owners. Staff's recommendations are below:

    a. One efficient way to study economic cycling could be to perform a modeling run, likely in AURORA or PLEXOS, that allowed any generator to cycle for economic reasons, with the constraint that system reliability must be maintained.

b. It is important to consider all units in the same study in order to identify which units, if any, would be the best candidates for economic cycling.

c. The only restrictions should be those that are based on any actual constraints that would prevent a unit from economically cycling.

If a plant or unit that was at one time identified as having the potential to cost-effectively cycle is shown to no longer be a good candidate after discussions with co-owners or further study of that plant/unit's expected EIM revenues, then the plant could be removed from consideration for economic cycling for a time.

Staff would expect PacifiCorp to document its EIM revenue analysis and conversations with co-owners and be prepared to provide that documentation in power cost proceedings.

d. In the economic cycling study recommended by Staff to inform PacifiCorp's coal contract negotiations, which should be performed separately from the modeling used in the TAM, existing minimum take provisions should be modeled accurately as they are defined by existing contracts. This includes the removal of minimum take provisions from modeling after the expiration of the relevant contracts.

e. The process of studying economic cycling for the purpose of informing coal contract negotiations should not be limited to a single modeling exercise, but should include conversations with co-owners and further study of expected EIM revenue when warranted. Additionally, studies of economic cycling should be repeated as often as necessary to ensure that PacifiCorp has identified all candidates for economic cycling and explored those possibilities well enough to show whether economic cycling can be pursued at each identified unit/plant while maintaining reliability.

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 02.

Data Request No 02:

02. Is the "full assessment" described at Staff/1400, Anderson/10, lines 5-7 different from, or the same as, the study of economic cycling that Staff recommends at Staff/1400, Anderson/8, lines 14-21. If the "full assessment" is different, please explain the differences.

Staff Response No 02:

02. Staff's "full assessment" described at Staff/1400, Anderson/10, lines 5-7 and the study of economic cycling at Staff/1400, Anderson/8, lines 14-21 do not necessarily need to be different studies. They could both be achieved through a process of studying economic cycling as described in Staff's response to PacifiCorp's Data Request No 01.

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 03.

Data Request No 03:

03. Does Staff agree that system reliability must be considered when determining whether to allow a coal unit to economically cycle? If not, please explain the basis for Staff's disagreement. If so, please explain how Staff recommends reliability be considered in the "full assessment" Staff recommends at Staff/1400, Anderson/10, lines 5-7.

Staff Response No 03:

03. Yes, reliability must be considered when determining whether to allow a coal unit to economically cycle.

The preferred method would be the use of a model that is capable of selecting opportunities for economic cycling endogenously while simultaneously ensuring system reliability.

If PacifiCorp does not have access to such a model, then economic cycling of the coal units would need to be studied one unit at a time through individual model runs for each unit. After identifying any units that could provide significant benefits through economic cycling, additional scenarios could be considered with more than one unit at a time studied for economic cycling in order to identify the best combination.

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 04.

Data Request No 04:

04. Refer to Staff/1400, Anderson/4, lines 7-9, where Staff testifies: "PacifiCorp's coal contracts should not be deemed prudent unless, prior to execution, economic cycling is considered and the minimum take commitment level is kept as low as reasonably possible."

a. Has Staff previously recommended that a coal supply agreement is imprudent because PacifiCorp did not consider economic cycling? If Staff has previously made this recommendation, please identify the docket, witness, and relevant testimony where the recommendation was made.

b. Is it Staff's position that a coal supply agreement is imprudent unless economic cycling is considered for every single unit in the Company's generation fleet or is it sufficient to consider economic cycling for the coal plant that will be supplied by the coal supply agreement that is subject to the prudence review? For example, is it Staff's position that a coal supply agreement for the Dave Johnston plant is imprudent even if PacifiCorp considered economically cycling the Dave Johnston plant but did not, in the same study, consider economically cycling the Hunter plant.

c. Has Staff performed any quantitative analysis showing that if the Company had considered economic cycling in the manner that Staff recommends, the level of generation at Hunter, Craig, or Dave Johnston would have been materially lower than the level of generation relied on by the Company when negotiating the coal supply agreements? If Staff has performed this analysis, please provide it.

d. Does Staff agree that if the Company had considered economic cycling in the manner that Staff recommends, that the new coal supply agreements for Hunter, Dave Johnston, and Craig would still include minimum take requirements? If not, please explain the basis for Staff's disagreement.

Staff Response No 04:

04. Refer to Staff/1400, Anderson/4, lines 7-9, where Staff testifies: "PacifiCorp's coal contracts should not be deemed prudent unless, prior to execution, economic cycling is considered and the minimum take commitment level is kept as low as reasonably possible."

a. Staff is not aware of another time that it has recommended coal contracts be deemed imprudent unless economic cycling is considered prior to execution.

b. As described in my rebuttal testimony, Staff's position is that economic cycling needs to be studied for the system as a whole, as PacifiCorp's generation is inter-dependent. In PacifiCorp's hypothetical, Staff's position is a *new* coal supply agreement for the Dave Johnston plant *would be* imprudent even if PacifiCorp considered economically cycling the Dave Johnston plant but did not, in the same study, consider economically cycling the Hunter plant.

However, to be clear, Staff is not challenging the prudence of coal contracts that are already executed and included in rates in accordance with the Commission's long-standing prudence standard. As such, Staff's prudence determination and remedy has focused on the new coal contracts. Moving forward, if any units are shown to be good candidates for economic cycling over the next few years, then PacifiCorp should seek a lower minimum take level in its next coal contract for that unit to accommodate the possibility of economic cycling in practice.

c. No.

d. Staff objects to this request as calling for conjecture and speculation. Without waiving this objection, Staff responds as follows:

Staff is unable to speculate about whether/how a contract which PacifiCorp and a third party negotiate would be impacted by PacifiCorp's additional analysis of economic cycling and minimum take provisions. Staff's concern, and the basis for its prudence recommendation, is the lack of analysis done by PacifiCorp and how such analysis might have impacted PacifiCorp's approach to negotiating the contract terms, including minimum take provisions.

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 05.

Data Request No 05:

05. Refer to Staff/1400, Anderson/11, lines 10-12 where Staff testifies: "However, because the Company did not perform an analysis of economic cycling on its system as a whole or at Dave Johnston, Staff continues to recommend that the new contract at Dave Johnston be deemed imprudent[.]" Is it Staff's position that generation levels at the Dave Johnston plant would have been lower if the GRID study used to support the Dave Johnston coal supply agreement negotiations allowed other coal units to economically cycle? If so, please explain the basis for Staff's position.

Staff Response No 05:

05. No. However, given that the coal units have not been studied for economic cycling potential, it is impossible to tell whether a different minimum take level would have been more cost-effective at Dave Johnston.

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 06.

Data Request No 06:

06. Has Staff performed any quantitative analysis demonstrating that the expected generation levels for Hunter, Dave Johnston, and Craig over the term of each plant's new coal supply agreement(s) subject to Staff's proposed adjustment are expected to fall short of the minimum take levels included in the new coal supply agreement(s)?

    a. Has Staff quantified the net power cost impact of imputing a reasonable minimum take level for each of the five new coal supply agreements?

Staff Response No 06:

06. No.

    a. No.

Date: August 18, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Rose Anderson
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's First Set of Data Request No 07.

Data Request No 07:

07. Does Staff agree that the 2022 TAM filing removed the "must run" setting from GRID thereby allowing all coal units to economically cycle? If Staff disagrees, please explain the basis for the disagreement.

    a. Does Staff agree that even without the "must run" setting in GRID, the model dispatches Hunter, Dave Johnston, and Craig above the minimum take levels included in the new coal supply agreements that are subject to Staff's proposed adjustment?

Staff Response No 07:

07. Yes. Staff agrees that for purposes of setting rates for the TAM year, the removal of the "must run" setting in GRID allows units to do a level of economic cycling. However, Staff's concern is that the GRID analysis used to inform coal contract negotiations does not generally consider economic cycling, regardless of what is modeled in GRID in the 2022 TAM.

    a. Yes, the GRID model dispatches Hunter, Dave Johnston, and Craig above the 2022 minimum take levels in the new coal supply agreements for the 2022 TAM forecast. However, it cannot be determined whether the power cost forecasting model will dispatch the plants above their minimum take levels in future TAM forecasts during the duration of the new contracts.

Date: August 20, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Moya Enright
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – Second Set of Data Request No 08:

Data Request No 08:

08. Refer to Staff/1000, Enright/7, lines 1-2. Please update this chart to reflect the total adjustments Staff is now sponsoring or supporting.

a) Without the adjustments that Staff is sponsoring or supporting in this case, does Staff contend that PacifiCorp will over recover its reasonable and prudent net power costs (NPC)?

b) Does Staff agree with this statement: PacifiCorp has generally under recovered its NPC in Oregon since 2008. If yes, please explain whether and how Staff has considered PacifiCorp's history of NPC under recovery since 2008 in proposing to reduce PacifiCorp's NPC forecast by approximately $10 million. If no, please explain why Staff disagrees with this statement.

c) Please identify any Staff-proposed or supported adjustments going back to the 2016 TAM that have increased the NPC forecast used to set rates in the TAM or were otherwise designed to address PacifiCorp's chronic NPC under recovery. For each adjustment identified, please list the docket, the witness, and the citation to the relevant testimony.

Staff Response No 08:

08. The requested updated table is provided below.

Staff notes that the $0 adjustment to the EIM Allocation Factor reflects the removal of the change proposed in PacifiCorp's reply filing (PAC/400, Staples,9).

#	Issue	Oregon-Allocated ($)
A	EIM Allocation Factor	$ -
B	Other revenues - Expiring Contract	$ 2,986,282
C	Other revenues - Fly Ash	$ (929,973)
D	BCC materials and supplies	$ (1,175,112)
E	PURPA QFs	$ (1,530,000)
F.1	Market Caps – Primary recommendation	$ (5,100,000)
F.2	Market Caps – Secondary recommendation	$ (3,358,757)
G	Nodal Pricing Model	$ (2,250,934)
H	"Wapa Firm Trans" correction	$ (609,086)
Total Adjustments		$ (8,608,823)
Total Adjustments (secondary recommendation F.2)		$ (6,867,580

a) Staff objects to this request as ambiguous and calling for pure speculation. Staff further objects to this request as not reasonably calculated to lead to admissible evidence. Without waiving these objections, Staff responds as follows:

Staff is unclear on what "over recover…reasonable and prudent net power costs" means within the context of the TAM proceeding, which is a forecast of normalized net power costs. Actual recovery is an issue for the corresponding PCAM proceeding, and the results of that will depend on several factors, including actual operations, and will not be known until after the conclusion of 2022. Staff's adjustments in this case are intended to produce a reasonable and accurate forecast of normalized 2022 net power costs. For the reasons set forth in Staff's testimony, Staff finds that PacifiCorp's request in this case is overstated.

b) Staff objects to this request as unduly burdensome on the grounds that it seeks information in the possession of, known to or otherwise equally available to PacifiCorp. Staff also objects to this request as vague and ambiguous. Without waiving this objection, Staff responds as follows:

Analysis of over- or under-recovery depends on the outcome of the corresponding PCAM. Staff finds that the results in the Company's prior PCAM proceedings speak for themselves. From a regulatory perspective, as recently affirmed by the Commission in Order No. 20-473, the TAM and PCAM structure allow for just and reasonable rates while balancing risk between shareholders and ratepayers. The Commission expressly declined to adopt PacifiCorp's proposal to eliminate deadbands, sharing and the earnings test. As such, generally speaking, Staff disagrees that from a ratemaking perspective, PacifiCorp has inappropriately under-recovered its NPC in Oregon since 2008.

To the extent that PacifiCorp may have under-recovered NPC relative to its forecast, Staff does not explicitly consider PacifiCorp's specific over- or under-recovery of NPC from prior years when making principled recommendations to improve the accuracy and reasonableness so of the TAM forecast, which is forward-looking. Staff notes in the 2018 TAM, PacifiCorp stated that "the evidence demonstrates that the GRID model, together with the refinements approved by the Commission, produces a reasonable and accurate NPC forecast." (UE 323 – PAC/400, Wilding/3-4).

c) Staff objects to this request as unduly burdensome on the grounds that it seeks information in the possession of, known to or otherwise equally available to PacifiCorp. Staff further objects to this request as irrelevant and not reasonably calculated to lead to admissible evidence. Without waiving the above objections, Staff responds as follows:

Staff did not undertake an exhaustive review of prior TAM proceedings since 2008 to determine all adjustments by all Staff, as that is information equally available to the Company and unduly burdensome to Staff, as well as generally irrelevant to normalized 2022 NPC. However, Staff notes that in this proceeding (UE 390), Staff witness Curtis Dlouhy proposed changes to the Company's method of forecasting EIM benefits that resulted in a decrease to company-wide forecasted EIM benefits (i.e. an increase to NPC). Please see Staff/800, Dlouhy/3-23. The Company accepted Staff's methodology change in its reply testimony (PAC/400, Staples/82).

Further, in both UE 307 and UE 323, Staff recommended that PacifiCorp undertake a backcast in order to ensure the accuracy and reasonableness of the TAM forecast, and to help identify and explain whether any forecast errors are related to inputs or model specification. (UE 323 – Staff/200, Kaufman/9). In both proceedings, the Company argued against Staff's recommendation.

Date: August 20, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Curtis Dlouhy
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's Second Set of Data Request No 11.

Data Request No 11:

11. Does Staff agree or disagree with the following statement: "GRID forecasts offsetting purchases and sales at the same location for the same delivery hour in its balancing purchases and sales."

Staff Response No 11:

11. Staff does not agree with this statement. Staff would welcome changes to the Company's model to realistically represent offsetting sales rather than changes that bring its model further from the market it represents, such as the Company's proposed changes to market caps.

Date: August 20, 2021

TO: PacifiCorp
825 NE Multnomah Street STE 2000
Portland OR 97232

FROM: Curtis Dlouhy
Senior Economist
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 390 – PacifiCorp's Second Set of Data Request No 12.

Data Request No 12:

12. Please refer to Staff/1200, Dlouhy/7, lines 9-10, where Staff asserts that "problems with the 'average of averages' method will still remain." Please specify the problems Staff has identified with this method and provide all quantitative analysis Staff conducted to support this assertion.

Staff Response No 12:

12. The remaining problems are that the "average of averages" method of forecasting off-system sales do not actually represent what can possibly be sold at market hubs, as was discussed in Staff/800, Dlouhy/29-30. Namely, that even imposing market caps brings the GRID model further away from representing the way the Company transacts in the market and each hub's true market depth. Staff's quantitative analysis to demonstrate the identified discrepancies are summarized up in Table 2 on Staff/800, Dlouhy/37. Values in Table 2 was calculated using the workpaper "ORTAM22 Dir_Market Capacity DEC20 CONF" provided by the Company.

PUBLIC UTILITY COMMISSION
OF OREGON

UE 390

PACIFICORP

PAC/1601

Excerpts from PacifiCorp's Workpapers

REDACTED

August 23, 2021

THIS EXHIBIT IS CONFIDENTIAL PER GENERAL PROTECTIVE ORDER IN DOCKET UE 390 AND IS PROVIDED SEPARATELY

PUBLIC UTILITY COMMISSION
OF OREGON

UE 390

PACIFICORP

PAC/1602

Docket No. UE 374 Excerpt from Order No. 20-473

August 23, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.	ORDER

DISPOSITION: PARTIAL STIPULATION ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

I. SUMMARY

This order addresses PacifiCorp, dba Pacific Power's request for a general rate revision. Overall, we approve a decrease to PacifiCorp's revenue requirement of approximately $20.9 million, representing a 1.6 percent decrease from the company's previous rates. In its initial filing, PacifiCorp sought an increase of $78.0 million, or approximately 6 percent. During the course of the proceeding, PacifiCorp revised its requested increase to $46.3 million, or approximately 3.5 percent. In this order, we address disputes regarding the company's revenue requirement, exit dates and exit orders for certain coal-fueled resources, and rate adjustment mechanisms. We then address the partial stipulation regarding rate spread and rate design.

We note that our exclusion of incremental decommissioning costs from rates, pending further investigation, represents approximately $27.3 million of the company's $46.3 million request. We expect the parties to promptly undertake that investigation and we anticipate approving an additional rate change following a thorough vetting of the company's decommissioning cost studies.

As a result of changes to general rates, customers will experience a decrease on their bills effective January 1, 2021. More detailed rate impacts will be provided in the company's compliance filing. Customers will experience an additional decrease in their bills effective January 1, 2021, due to a decrease in the company's transition adjustment has access to current and detailed data in order to identify these areas with specificity in its audits.

Finally, we believe it is important to monitor the implementation of the mechanism to allow us to review its operation and ensure that its goals are being met, and thus adopt certain reporting and review requirements independent of any cost recovery. We direct PacifiCorp to include in its annual filing a narrative description and breakdown of each: (1) vegetation management and wildfire mitigation O&M expenditures associated with the amount recovered in base rates, (2) total incremental vegetation management O&M expenditures, (3) total incremental wildfire mitigation O&M expenditures, and (4) total incremental wildfire mitigation capital expenditures. Additionally, the company must include a narrative description of the effect, if any, that the earnings test and performance metrics had on the recovery of incremental costs. In the event that PacifiCorp does not incur incremental costs that would be eligible for recovery through the mechanism in a given year in any category, the filing should address the reasons such costs did not materialize as expected. We direct Staff to review the company's annual filing and present a memorandum summarizing any findings and recommendations regarding the operation of the mechanism. This review should be conducted by both Safety and Rates, Finance, and Audit Staff.

We recognize that implementation of this complicated mechanism likely will reveal the need for clarification of certain details. We encourage the stakeholders to collaborate as this mechanism is put into place, and to seek clarification from the Commission as needed.

F. The Current TAM and Proposed Annual Power Cost Adjustment

1. Summary

In this section, we address PacifiCorp's proposed APCA. We address the three parts of the company's proposal: (1) to combine the TAM and Power Cost Adjustment Mechanism (PCAM) into a single filing, (2) to remove PCAM deadbands, sharing, earnings test, and (3) to update certain TAM guidelines. Within the TAM guidelines section we also address CUB's proposal on wheeling revenues.

a. Combining the TAM and PCAM into a Single Proceeding

PacifiCorp currently recovers its NPC through the TAM. PacifiCorp proposes to replace the TAM and its companion true-up mechanism, the PCAM, with a single annual power cost filing, APCA. The APCA would contain a forecast of NPC for the next year and a true-up of NPC for the previous year. For example, an APCA filed in April 2021 would contain a forecast of 2022 power costs and a true-up of 2020 power costs. PacifiCorp proposes to remove the current PCAM deadbands, sharing bands, and earning test from the APCA true-up, or from the PCAM if it remains. The annual filing would undergo our prudence review, similar to the current TAM process. The effective APCA rate schedule would combine the NPC forecast and true-up components.[601]

To summarize the parties' positions, PacifiCorp maintains that the APCA is necessary to allow a fair opportunity to recover NPC. Staff, CUB, AWEC, KWUA, and SBUA assert that the current TAM and PCAM are functioning well. The parties believe that PacifiCorp is within a reasonable zone of its authorized return, that removing the deadbands and earning test would guarantee dollar-for-dollar recovery of power costs and an unfair outcome for customers, and that the current COVID-19 pandemic is not the time to increase customers' price risk.

First, we describe the parties' positions on the cause of PacifiCorp's NPC under-recovery and the potential effect of the APCA proposal. Parties agree that PacifiCorp has generally under-recovered power costs since 2008, but disagree with PacifiCorp about the causes and possible solutions for PacifiCorp's NPC under-recovery.

PacifiCorp asserts that increased renewable energy necessitates a change to the TAM and PCAM. PacifiCorp states that renewable generation results in many unforecastable transactions that are resulting in losses.

AWEC analyzed data to show that, as wind power increased in recent years, the NPC forecast has been more accurate. Staff adds that new renewables should not have any material impact on power cost recovery going forward because PacifiCorp has already agreed to provide customers with the promised benefit of almost its entire wind fleet through set capacity factors.[602]

Staff concedes that GRID over-optimizes and finds economic sales that PacifiCorp does not realize in actual operations, but Staff states that PacifiCorp's imminent use of the AURORA model may fix this problem.[603] Both AWEC and Staff believe that AURORA combined with the day-ahead/real-time balancing transactions (DA/RT) adjustment may also alleviate the under-recovery, as the DA/RT adjustment has helped PacifiCorp have closer to full recovery since its implementation.[604]

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601 PAC/3602, Wilding/7 ("All NPC will be collected through a new Schedule 201, Annual Power Cost Adjustment, which will be applied as a rider to Schedule 200.").
602 Staff/2400, Gibbens/15 ("parties to the 2019 TAM agreed to use the P50 capacity factors used to justify PacifiCorp's new and repowered wind fleet.").
603 Staff/2400, Gibbens/9 (quoting Energy Exemplar, the creators of AURORA that "there are options for introducing forecast error * * * to model uncertainty between commitment and dispatch.").
604 Staff/2400, Gibbens/10 ("In looking at the average deviation based on the numbers in PAC/2000, Wilding/55, Table 6, the post-DA/RT deviation is roughly 1/3 the size of the pre-DA/RT deviation.").

PacifiCorp disputes that the new system model AURORA is an opportunity to fix the problem with NPC under forecasting. PacifiCorp states that AURORA is like all models that run up against the uncertainties of short-term weather and unknown market activity, AURORA will not incorporate forecast error if the TAM continues to be based on normalized, median inputs, and AURORA may continue to over forecast sales as all models seek cost reductions with unrealistically large volumes of very small trades.[605] PacifiCorp concedes that it is possible that better use of the DA/RT adjustment could reduce the problem, but that the market conditions driving the problem are not stable, so a creative insight would be required each year, and a lot of regulatory debate on how to set more realistic adjustment terms.[606]

b. Remove Deadbands, Sharing, and the Earnings Test from the PCAM

PacifiCorp seeks to remove the deadbands, sharing and earnings test from the PCAM, while the parties recommend maintaining the PCAM structure. The PCAM deadbands provide that PacifiCorp absorbs any variance between negative $15 million and positive $30 million. After the deadbands and a 10 percent sharing mechanism, an earnings test provides that if PacifiCorp's earned ROE is within plus or minus 100 basis points of its allowed ROE, there is no recovery from or refund to customers.

PacifiCorp maintains that removing the PCAM deadbands and earnings test will invite robust review of actual NPC. PacifiCorp asserts that the current PCAM puts PacifiCorp at risk for something it cannot control or improve, hourly deviations in renewables output and the costs of balancing transactions.[607] PacifiCorp states that removing deadbands and risk sharing mechanisms from the PCAM would shift the focus to activities the company can control.

PacifiCorp further argues that our power cost principles are outdated and the PCAM does not meet its design principles.[608] PacifiCorp maintains that the majority of other states now have full flow-through mechanisms for NPC-type costs due to new markets and new technologies.

Staff, CUB, and AWEC assert that the PCAM is appropriately operating in line with the Commission's original principles. First, PCAM recovery is limited to unusual events. Second, there are no adjustments if overall earnings are reasonable. Third, the PCAM is revenue neutral. Lastly, there is the long-term operation of the PCAM. Staff, CUB and

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605 PAC/3700, Graves/31.
606 PAC/3700, Graves/32.
607 PacifiCorp Closing Brief at 10.
608 PacifiCorp Closing Brief at 11.

SBUA state that the PCAM is well-functioning and should be maintained with the above principles.[609] If changes are contemplated, Staff suggests cutting either the deadbands or the earnings test in half, and CUB suggests a wider investigation.

Parties including Staff, CUB, AWEC and KWUA believe the overall PCAM policy is sound, with incentives for PacifiCorp to manage costs and with customer protections to allocate risks. The parties state the PCAM appropriately shares risk between customers and PacifiCorp, and the balance is reasonable with the backdrop of the company's recent earnings level and overall rates. KWUA notes that if the Commission were to adopt the company's proposal, the reasonable ROE may need to be changed. CUB and SBUA both argue that due to the ongoing pandemic, this is not the right time to shift risk to customers.

c. Changes to the TAM Guidelines

PacifiCorp and parties request changes to the TAM Guidelines, even if we retain the current TAM and PCAM mechanisms. PacifiCorp recommends that company-owned coal mines like Bridger Coal Company be added to the costs that are updated in PacifiCorp's reply testimony or TAM reply update. AWEC requests that the Commission modify the current guidelines to require concurrent filing of all workpapers on the same day as the initial filing. CUB requests a change so that annual wheeling revenues are forecast annually alongside other variable costs and benefits. Calpine requests we implement the parties' agreement so a sample calculation of the five-year direct access opt-out charge is included in the annual TAM filing.

CUB explains that currently, wheeling revenues are recovered in base rates and PacifiCorp files an annual deferral to true-up the difference between what is captured in base rates and the actual revenue PacifiCorp realizes. Since PacifiCorp's last rate case, this amount has averaged $6 million a year.[610] CUB states that annual wheeling revenues are appropriately grouped with the other variable costs and benefits in the TAM and that the Commission disfavors deferred accounting for recurring events. CUB further observes that Utah includes wheeling revenues in its NPC tracker.

PacifiCorp opposes moving the wheeling revenues, stating that wheeling revenues are not associated with the costs of PacifiCorp's purchases and sales, but are charges for other entities using PacifiCorp's transmission system. PacifiCorp states that its wheeling revenues will be more stable going forward because markets like the EIM have led to a

[609] CUB Reply Brief at 18; SBUA Prehearing Brief at 7 (asserting the Commission should maintain the PCAM principles from docket UE 246).
[610] CUB Reply Brief at 29.

shift away from purchases of non-firm transmission to facilitate short-term bilateral sales.[611]

AWEC requests a change to the TAM guidelines to require all workpapers to be provided contemporaneously with PacifiCorp's initial NPC filing.[612] AWEC explains that the 15-day waiting period imposes a burden on parties given the short procedural schedule in the TAM. CUB supports AWEC's request. PacifiCorp opposes the change, stating that all workpapers are already provided except four sample NPC sample calculations and that the additional requirement would be burdensome on the company, and further, that the parties did not demonstrate that the existing process has hampered their review of the TAM.[613]

Calpine's request, a sample calculation for the five-year direct access program, has already been agreed to in the 2021 TAM, docket UE 375. In this proceeding, PacifiCorp and Calpine request implementation of a requirement to provide the sample calculation no later than 30 days after the initial filing.[614]

Lastly, PacifiCorp suggested a change to the TAM guidelines to expand the updates in its TAM rebuttal/reply update to include coal contracts for mines directly or indirectly owned by the PacifiCorp.[615] Currently PacifiCorp may not update these coal costs after its initial TAM filing.

2. Resolution

We decline to adopt PacifiCorp's proposal for a single power cost recovery mechanism. We further decline PacifiCorp's alternate proposal to retain the TAM but remove the PCAM's deadbands, sharing, and earnings test. PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs, and PacifiCorp has not shown that a redesign is necessary. Stakeholders have been working with the Commission's power cost recovery structure and policy for almost a decade.[616] For PacifiCorp specifically, the TAM and PCAM proceedings have stabilized in the last three years, with fewer contested issues compared to previous years.[617] At the same time, other PacifiCorp-specific power cost issues are

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611 PAC/3600, Wilding/22.
612 AWEC/100, Mullins/41.
613 PAC/3600, Wilding/20; PAC/2000, Wilding/82.
614 PAC/2000, Wilding/ 82-83; Calpine Prehearing Brief at 3.
615 PAC/3602, Wilding/4.
616 PAC/2000, Wilding/53, *citing In the Matter of PacifiCorp 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 2 (Oct 17, 2007); Order No. 12-493 at 13.
617 We need not specifically decide whether the PCAM parameters are outdated relative to other states, because we base our decision on Oregon policy. The ALJ admitted extra exhibits and testimony into the record from CUB and PacifiCorp on this issue in a separate ruling.

destabilizing, with a transition to nodal pricing underway, new TAM and IRP models, and the company's work on the MSP framework issue of new resource assignment that may alter the intrastate dynamic allocation of power costs based on load. We can imagine looking at our PCAM parameters in the future when we consider these other significant power costs (around 2024), but this year is not the appropriate time for a redesign.

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 transactions to increase GRID's balancing costs.[618] 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."[619] 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.[620]

We also decline to adopt any changes to the TAM Guidelines, as requested by PacifiCorp and the parties. The TAM Guidelines are a set of rules that largely govern the company and parties' behind-the-scenes deadlines and filings. We hesitate to make changes to the guidelines absent consensus. We decline AWEC's suggestion to require all workpapers to be filed with PacifiCorp's initial filing. The TAM Guidelines use staggered filing deadlines so that parties have a preview of power costs before the filing, some workpapers concurrent with the initial filing, other workpapers five days later, and a third group "as soon as practical after filing, delivered on an as-ready basis, but no later than 15 days after the Initial Filing."[621] This language seems to balance the parties' interest in prompt receipt of information with PacifiCorp's need to process the data. As we have declined all suggested changes to the TAM or PCAM, we also decline CUB's suggestion to add wheeling revenues to the TAM. Moving wheeling revenues to the TAM would increase the risk on PacifiCorp by subjecting the wheeling revenue forecast to the

[618] *See* PAC/2000, Wilding/65 (Table 7 showing the annual DA/RT impact from 2016-2019 of approximately $8 million total-system).
[619] Staff/2400, Gibbens/19-22.
[620] Order No. 20-392 at Appendix A at 5 (stating PacifiCorp will hold a workshop on the transition to AURORA and provide access to the model).
[621] *In the Matter of PacifiCorp 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 16-17 (Jul 16, 2009).

PCAM's deadbands. In this order, we do not alter the existing risk sharing balance in the TAM and PCAM. Lastly, Calpine's specific change for a sample opt-out calculation may be made consistent with our adoption of the parties' stipulation in docket UE 375.

G. Miscellaneous Issues

1. Schedule 272

a. Summary

On September 27, 2019, PacifiCorp filed a notice of exception to the competitive bidding requirements, explaining the circumstances leading to the acquisition of the Pryor Mountain wind resource, and explaining that the project was a time-limited opportunity to acquire a resource of unique value to its customers. In response comments filed, Staff raised a concern that the Pryor Mountain wind project should have been pursuant to a voluntary renewable energy tariff (VRET), to ensure protections for other cost of service customers. As addressed above, Staff does not oppose the inclusion of the Pryor Mountain wind resource in rate base. However, Staff recommends that the Commission open an investigation into PacifiCorp's Schedule 272, and direct PacifiCorp to refrain from entering into contracts with Schedule 272 customers that include supplying RECs from utility-owned resources during the pendency of that investigation. Staff contends that, based on its review, Schedule 272 may be a VRET regardless of whether the underlying resource is utility-owned or a power purchase agreement (PPA), on the basis that the RECs sold might meet the definition of a bundled REC. Staff contends that the purpose of its recommendation is to ensure that the company's Schedule 272 is not a VRET that should be subject to the Commission's VRET guidelines. Calpine shares Staff's concerns regarding future uses of Schedule 272, especially for utility-owned resources, and supports Staff's proposal to open an investigation. Calpine maintains that the issues addressed by 2014 Regular Session House Bill 4126 and the VRET Guidelines are clearly implicated by PacifiCorp's use of Schedule 272 to acquire new utility-owned resources.

PacifiCorp opposes Staff's proposed investigation into Schedule 272, and asserts that restrictions pending investigation are unnecessary. PacifiCorp contends that a recent Commission decision states that Schedule 272 is not a VRET because it does not involve the sale of bundled RECs.[622] PacifiCorp represents that it does not anticipate entering into another Schedule 272 agreement involving a utility-owned facility in the foreseeable future, but agrees that it would confer with stakeholders before proceeding with any such transaction if it does arise. As a result, PacifiCorp contends that there are no near-term

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[622] PacifiCorp Closing Brief at 43, *citing In the Matter of PacifiCorp, d/b/a Pacific Power, Advice No. 16-012 Changes to Schedule 272*, Docket No. ADV 386, Order No. 17-051 (Feb 13, 2017).

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

PACIFICORP

PAC/1603

Docket No. UE 374 Excerpt from Staff/2400 Rebuttal Testimony of Scott Gibbens

August 23, 2021

CASE: UG 374
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2400

Rebuttal Testimony

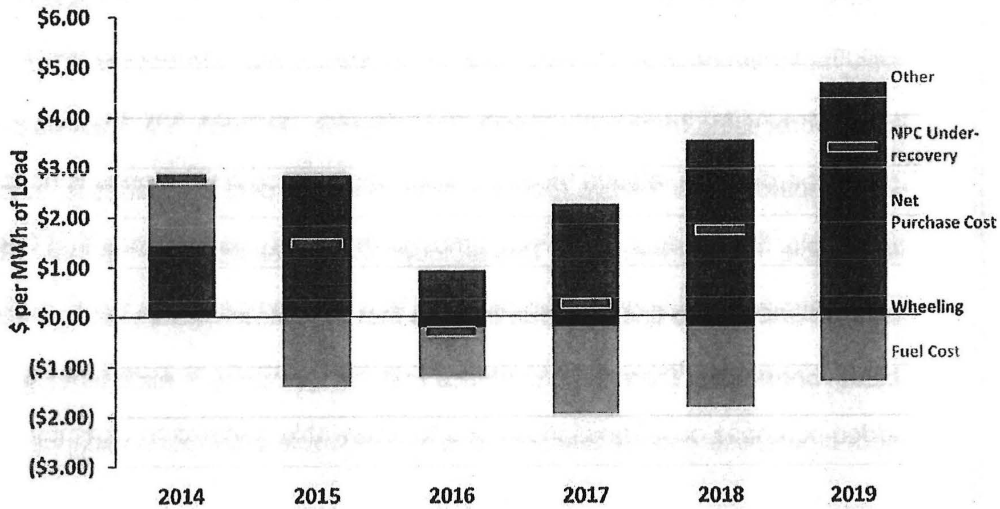
Redacted
July 24, 2020

Q. How did Staff come to the conclusion that added transactions are not driving under-recovery?

A. Staff provides Confidential Figure 2 from PAC/3000 for reference:

[BEGIN CONFIDENTIAL]

Confidential Figure 2: Composition of NPC Under-recovery for PacifiCorp in Oregon (with 2019 data)

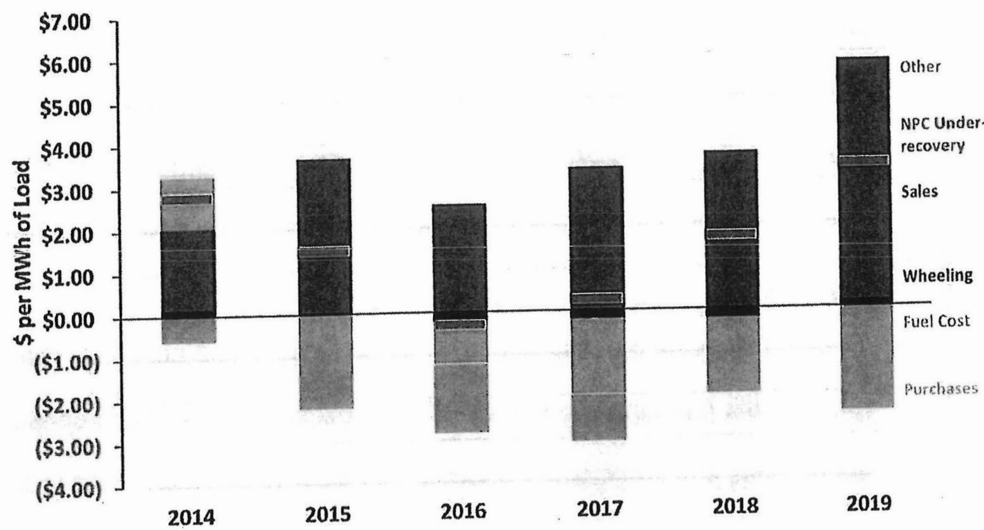


Notes:
[1] Calculated based on PacifiCorp's PCAM data from 2014 - 2019.
[2] "Other" refers to generating expenses from wind and solar owned by PacifiCorp.
[3] The actual NPC in 2016 does not include the unusual Bridger Coal Company costs from that year.

[END CONFIDENTIAL]

Staff recreated the Company's figure, with purchases and sales broken out:

[BEGIN CONFIDENTIAL]

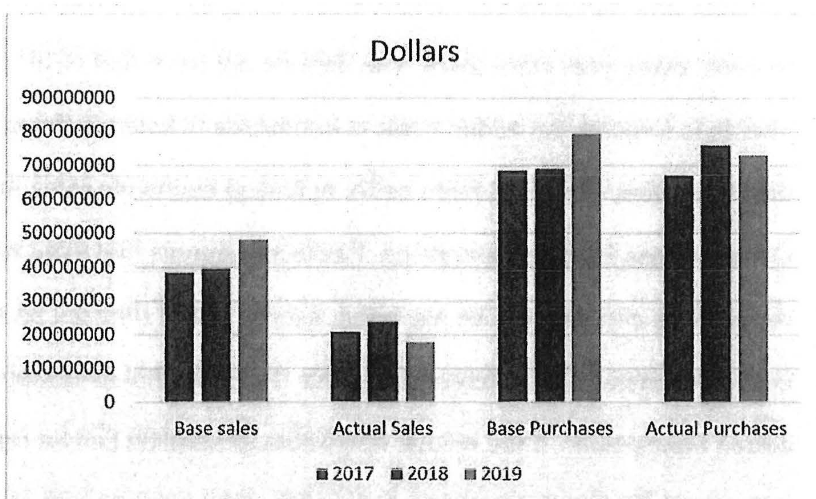


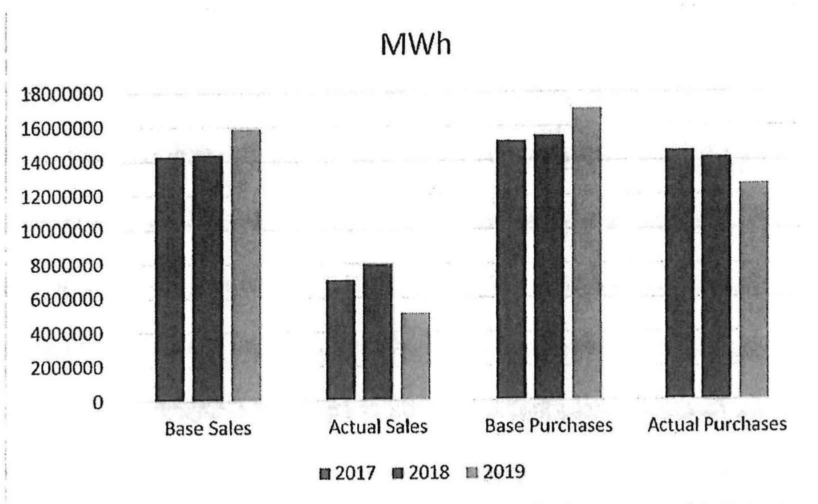
[END CONFIDENTIAL]

As evidenced by the above figure, system purchase costs have been over-forecast every year since 2014. The data do not show that GRID has been unable to forecast the added costs of purchases to balance the system, the data show that GRID has been better at finding economic sales than the Company has in actual operations. PacifiCorp argues that even when renewables generate above expected, excess power may not be able to be sold as economically as forecast, but this data does not necessarily point to added transactions. If the annual renewable generation can be reasonably forecast as the Company claims is possible, then even excess generation leading to uneconomic sales would need to also include lower than expected generation leading to uneconomic purchases. As the data show, this is simply not the case. Sales are being over-forecast while purchases are also being over-forecast. It is also not clear to Staff how unexpected over-generation would lead to less economic sales opportunities than expected, when the added generation was not forecast in the first place. It is more reasonable to assume that either PacifiCorp has been unable to efficiently optimize its system, or that GRID's perfect foresight is generally too good at economic dispatch.

To better illustrate the discrepancy in sales vs purchase accuracy, Staff provides the following two figures. They show the Company's forecasted vs actual sales and purchases excluding EIM transactions from 2017 to 2019 in dollars and MWhs.

[BEGIN CONFIDENTIAL]





[END CONFIDENTIAL]

The figures show that only one of the two market transaction types is largely inaccurate in the forecast. The added transactional costs are not apparent. A gross over-estimation of the sales benefit is. This is apparent in both the dollar and MWh metrics. It does not appear as though PacifiCorp performs numerous additional transactions at a loss, if that were the case the volume of trades would be largely the same or the Company would have higher actuals than is being realized. The Company's argument of additional transactions is only a theory unsupported by empirical evidence.

Q. Why did Staff exclude EIM from the above analysis?

A. There were several reasons that Staff excluded EIM transactional data from the analysis. The first is that only the dollar impact of the EIM is forecast in the TAM, transactional volumes are not. The second is that the Company accounts for EIM benefits in its actuals as a net amount, so imports and exports cancel each other out in a single line item. This is also why Staff only included the

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PACIFICORP

PAC/1604

Docket No. UE 344 Order No. 18-449

August 23, 2021

ORDER NO. 18 449

ENTERED NOV 30 2018

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 344

In the Matter of

PACIFICORP, dba PACIFIC POWER,

2017 Power Cost Adjustment Mechanism.

ORDER

DISPOSITION: STIPULATION ADOPTED

I. SUMMARY

In this order, we adopt the parties' stipulated agreement that the 2017 actual power costs for PacifiCorp, dba Pacific Power, were within the deadband of the company's power cost adjustment mechanism (PCAM) and that there should be no change in customer rates.

II. BACKGROUND

In Order No. 12-493, we established a PCAM for PacifiCorp to work in conjunction with the company's Transition Adjustment Mechanism (TAM). The PCAM is designed to allow the company to recover or refund the difference between actual net power costs (NPC) and the forecast NPC approved in the TAM and included in customer rates. [1] This docket is PacifiCorp's fifth PCAM filing.[2]

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[1] *See In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 14-15 (Dec 20, 2012) (establishing features of PacifiCorp's PCAM).

[2] *See In the Matter of PacifiCorp, dba Pacific Power, 2013 Power Cost Adjustment Mechanism*, Docket No. UE 290, Order No. 14-357 (Oct 16, 2014); *2014 Power Cost Adjustment Mechanism*, Docket No. UE 298, Order No. 15-380 (Nov 25, 2015); *2015 Power Cost Adjustment Mechanism*, Docket No. UE 309, Order No. 16-459 (Nov 30, 2016); *2016 Power Cost Adjustment Mechanism*, Docket No. UE 327, Order No, 17-524 (Dec 27, 2017) (all orders adopting stipulations, 2013 and 2014 PCAM filings resulted in no rate change due to the earnings test, and 2015 and 2016 PCAM filing resulted in no rate change due to the deadband).

PacifiCorp's PCAM contains a deadband, sharing mechanism, earnings test, and amortization cap.[3] The asymmetric deadband requires the company to absorb some normal variation of power costs, and is set at a negative annual power cost variance of $15 million and a positive annual power cost variance of $30 million. Any amount above or below the deadband is subject to the sharing mechanism and earnings test. PacifiCorp calculates its PCAM, and any resulting adjustment is reflected in its tariff Schedule 206.

The sharing mechanism provides PacifiCorp the incentive to manage costs effectively by allocating 10 percent of the remaining variance to PacifiCorp and the balance to customers. The earnings test, which helps guard against over- and under-earning, eliminates any power cost adjustment if the company earns within plus or minus 100 basis points of its allowed return on equity (ROE). Finally, an amortization cap limits amortization of deferred amounts under the PCAM in any year to 6 percent of PacifiCorp's revenues for the preceding calendar year.

The Oregon Citizens' Utility Board (CUB) and Commission Staff participated in this docket. All parties filed a joint stipulation and supporting testimony in support of the stipulation.

III. PARTIES' FILINGS

PacifiCorp's initial PCAM filing showed 2017 actual NPCs were above base costs by $2.3 million on an Oregon-allocated basis. The company's base NPC were set in the 2017 TAM in docket UE 307. PacifiCorp stated that, because the $2.3 million PCAM variance is within the positive $30 million deadband, the company would absorb the difference and there would be no rate adjustment. PacifiCorp's filing also showed that the company's 2017 earned ROE was 11.13 percent, and its allowed ROE is 9.80 percent.

PacifiCorp's initial testimony contains detailed explanations of the PCAM calculation, a summary of NPC differences compared to the TAM forecast, and a description of the impact of participating in the EIM. PacifiCorp explains several variations in its actual power cost compared to its forecast power costs. The main increase in power costs was due to a large decrease in off-system sales (which are a credit to NPC). However, this was offset by 23 percent higher hydro generation (with zero fuel cost), 7 percent less coal generated, and 40 percent less natural gas generation.

[3] Portland General Electric Company's PCAM contains the same components. *See e.g.*, *In the Matter of Portland General Electric Company, 2016 Annual Power Cost Variance Mechanism*, Docket No. UE 329, Order No. 17-504 (Dec 18, 2017).

IV. STIPULATION

Following settlement discussions and prior to the filing of testimony by Staff and CUB, all parties reached an agreement and submitted a stipulation and joint testimony in support of the stipulation. PacifiCorp submitted a motion to admit its direct testimony and exhibits. PacifiCorp, Staff, and CUB also move to admit the stipulation and joint testimony in support of the stipulation. The motion is granted. The stipulation is attached to this order as Appendix A.

In the stipulation, the parties agree that the company's PCAM calculation for 2017 complies with Order No. 12-493 and results in no change to existing rates. The stipulation does not contain any changes to PacifiCorp's initial filing. The parties recommend we adopt the stipulation in its entirety.

V. DISCUSSION

The 2017 PCAM results in no rate change. The parties analyzed PacifiCorp's PCAM filing and workpapers, and agreed with PacifiCorp's calculations. We note that PacifiCorp's initial testimony in this PCAM contains thorough and clear explanation of the PCAM calculations and the variations in actual NPC compared to the TAM forecast. PacifiCorp committed to include this detail in the 2016 PCAM settlement, and we memorialized this requirement in last year's order. We find that the additional detail and explanation provides helpful context for understanding the PCAM and a useful connection to the annual TAM process. We adopt the stipulation in its entirety.

We also note that we recently determined that we do not have authority to allow deferrals of any costs related to capital investments.[4] In the future, Staff, PacifiCorp, and intervenors may need to review the items in the PCAM deferral to ensure capital costs are not included in the event the amounts deferred for the PCAM are amortized and put into rates.

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[4] *In the Matter of Investigation of the Scope of the Commission's Authority to Defer Capital Costs,* Docket No. UM 1909, Order No. 18-423 (Oct 29, 2018).

VI. ORDER

IT IS ORDERED THAT:

1. The stipulation between PacifiCorp, dba Pacific Power; the Oregon Citizens' Utility Board; and Staff of the Public Utility Commission of Oregon, attached as Appendix A is adopted.

2. PacifiCorp, dba Pacific Power's Schedule 206 rates should continue to be set at zero effective January 1, 2019.

Made, entered, and effective NOV 30 2018.

Megan W. Decker
Chair

Stephen M. Bloom
Commissioner

Letha Tawney
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

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.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 344

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2017 Power Cost Adjustment Mechanism	**STIPULATION**

INTRODUCTION

1. PacifiCorp d/b/a Pacific Power, Public Utility Commission of Oregon (Commission) Staff, and the Oregon Citizens' Utility Board (CUB) (collectively the Stipulating Parties) enter into this Stipulation to resolve all issues in docket UE 344, PacifiCorp's 2017 power cost adjustment mechanism (PCAM). No other party intervened in this docket.

BACKGROUND

2. The Commission approved PacifiCorp's PCAM in Order No. 12-493 in docket UE 246. The PCAM allows the recovery or refund of the difference between actual costs incurred to serve customers and the rates established in PacifiCorp's annual transition adjustment mechanism (TAM) filing. The amount recovered from or refunded to customers for a given year is subject to the following parameters:

- Asymmetrical Deadband – Any net power cost (NPC) difference between negative $15 million and positive $30 million is absorbed by the company.
- Sharing Mechanism – Any NPC difference above or below the deadband is shared 90 percent by customers and 10 percent by the company.

ORDER NO. 18 449

- Earnings Test – If the company's earned return on equity (ROE) is within plus or minus 100 basis points of the allowed ROE, there is no recovery from or refund to customers.
- Amortization Cap – The amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year.[1]

3. On May 15, 2018, PacifiCorp filed its PCAM for calendar year 2017. Attachment A to this Stipulation is a summary of the company's PCAM calculation. On an Oregon-allocated basis, actual PCAM costs exceeded base PCAM costs established in the 2017 TAM (Docket UE 307), by approximately $2.3 million.

4. After application of the deadband, there is no recovery for the 2017 PCAM.

5. The Stipulating Parties held a settlement conference on July 20, 2018. This conference resulted in an agreement resolving all issues in this docket.

AGREEMENT

6. The Stipulating Parties agree that PacifiCorp's PCAM calculation for calendar year 2017, as set forth in the company's initial filing and summarized above, complies with Order No. 12-493 and results in no change to existing rates.

7. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating Parties agree that this Stipulation will result in rates that meet the standard in ORS 756.040.

8. This Stipulation will be offered in to the record as evidence under OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and

[1] *In the Matter of PacifiCorp d/b/a Pacific Power's Request for a General Rate Revision*, Docket UE 246, Order No. 12-493 at 15 (Dec. 20, 2012).

any appeal, provide witnesses to sponsor the Stipulation at hearing, if required, and recommend that the Commission issue an order adopting the Stipulation.

9. The Stipulating 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 of the Stipulating Parties are entitled to withdraw from the Stipulation or exercise any other rights provided in OAR 860-001-0325(9). To withdraw from the Stipulation, a Stipulating Party must provide written notice to the Commission and the other Stipulating Parties within five days of service of the final order rejecting, modifying, or conditioning this Stipulation.

10. By entering into this Stipulation, no Settling Party approves, admits, or consents to the facts, principles, methods, or theories employed by any other Settling Party.

11. This Stipulation is not enforceable by any Settling Party unless and until adopted by the Commission in a final order. Each signatory to this Stipulation avers that they are signing this Stipulation in good faith and that they intend to abide by the terms of this Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Settling Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation. If the Commission rejects or modifies this Stipulation, the Settling Parties reserve the right to seek reconsideration or rehearing of the Commission order under ORS 756.561 and OAR 860-001-0720 or to appeal the Commission order under ORS 756.610.

12. This Stipulation may be executed in counterparts and each signed counterpart constitutes an original document.

This Stipulation is entered into by each Settling Party on the date entered below such Settling Party's signature.

ORDER NO. 18 449

PACIFICORP

By: ______________________

Date: 9/10/18

STAFF of the PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

ORDER NO. 18 449

PACIFICORP	STAFF of the PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
Date: ______________________	Date: 9/10/18

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

ORDER NO. 18 449

PACIFICORP	STAFF of the PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: 9/10/18

ORDER NO. 18 449

ATTACHMENT A

Oregon Power Cost Adjustment Mechanism
January 1, 2017 - December 31, 2017
Attachment A - Power Cost Adjustment Mechanism Calculation

Line No.		Reference	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total	
Actual:																
1	Total Company Adjusted Actual NPC	(2.1)	$ 138,590,571	$ 116,924,463	$ 113,018,110	$ 108,185,764	$ 115,246,592	$ 125,188,870	$ 152,659,742	$ 164,992,347	$ 131,586,685	$ 119,201,242	$ 113,389,351	$ 129,072,708	$ 1,528,056,446	
2	Actual Allocated PTC	(4.1)	(8,454,789)	(10,428,390)	(11,459,227)	(9,983,310)	(5,479,012)	(7,040,913)	(4,518,493)	(3,508,195)	(4,194,324)	(5,309,249)	(8,245,032)	(10,722,506)	(89,343,441)	(1,226,972)
3	Actual EIM Costs	(5.1)	381,196	381,196	381,196	381,196	381,196	381,196	381,196	381,196	381,196	381,196	381,196	381,196	4,574,351	673,839
4	Actual Other Revenues	(6.1)	(540,918)	(768,234)	(975,206)	(1,073,334)	(767,085)	(950,069)	(885,354)	(694,411)	(729,314)	(998,584)	(869,619)	(561,113)	(9,813,243)	841,510
5	Total PCAM Adjusted Actual Costs	Sum Lines 1 - 4	$ 129,976,060	$ 106,109,035	$ 100,964,872	$ 97,510,316	$ 109,381,691	$ 117,579,084	$ 147,637,091	$ 161,170,937	$ 127,044,242	$ 113,274,604	$ 104,655,895	$ 118,170,285	$ 1,433,474,113	
6	Actual System Retail Load	(8.1)	5,135,856	4,192,309	4,332,834	4,123,991	4,332,163	4,803,602	5,378,125	5,122,566	4,304,828	4,227,257	4,318,686	4,921,839	55,194,054	
7	Actual PCAM Costs $/MWH	Line 5 / Line 6	$ 25.31	$ 25.31	$ 23.30	$ 23.64	$ 25.25	$ 24.48	$ 27.45	$ 31.46	$ 29.51	$ 26.80	$ 24.23	$ 24.01	$ 25.97	
Base:																
8	Total Company Base NPC	(3.1)	$ 130,984,697	$ 118,713,689	$ 122,651,318	$ 117,262,046	$ 123,701,137	$ 129,386,833	$ 151,077,299	$ 143,761,067	$ 122,682,472	$ 121,024,247	$ 122,421,004	$ 131,903,005	$ 1,535,568,814	
9	Adjustment for Direct Access	(3.3)	(643,721)	(622,392)	(645,087)	(604,394)	(689,026)	(817,169)	(1,131,058)	(892,424)	(835,050)	(880,879)	(808,738)	(731,739)	(9,301,677)	
10	Base Allocated PTC	(2.2)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(7,343,039)	(88,116,470)	
11	Base EIM Costs	(3.4)	325,043	325,043	325,043	325,043	325,043	325,043	325,043	325,043	325,043	325,043	325,043	325,043	3,900,512	
12	Base Other Revenues	(6.2)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(887,896)	(10,654,753)	
13	Total PCAM Base Costs	Sum Lines 8 - 12	$ 122,435,083	$ 110,185,405	$ 114,100,338	$ 108,751,759	$ 115,106,218	$ 120,663,771	$ 142,040,349	$ 134,962,750	$ 113,941,530	$ 112,237,475	$ 113,706,374	$ 123,265,373	$ 1,431,396,427	
14	Base System Retail Load	(8.1)	4,941,400	4,367,578	4,526,701	4,222,416	4,452,704	4,549,044	5,262,767	5,101,299	4,442,315	4,340,824	4,474,948	4,958,612	55,640,607	
15	Base PCAM Costs $/MWh	Line 8 / Line 14	$ 24.78	$ 25.23	$ 25.21	$ 25.76	$ 25.85	$ 26.53	$ 26.99	$ 26.46	$ 25.65	$ 25.86	$ 25.41	$ 24.86	$ 25.73	
16	System PCAM Unit Cost Differential $/MWh	Line 7 - Line 15	$ 0.53	$ 0.08	$ (1.90)	$ (2.11)	$ (0.60)	$ (2.05)	$ 0.46	$ 5.01	$ 3.86	$ 0.94	$ (1.18)	$ (0.85)	$ 0.25	#
17	Oregon Retail Load	(8.1)	1,398,157	1,102,176	1,095,610	973,812	992,435	1,027,506	1,167,493	1,149,408	964,488	979,879	1,068,793	1,280,524	13,200,282	
Deferral:																
18	Monthly PCAM Differential - Above or (Below) Base	Line 17 * Line 16	$ 741,255	$ 90,791	$ (2,085,817)	$ (2,055,881)	$ (597,551)	$ (2,104,136)	$ 539,071	$ 5,754,384	$ 3,725,722	$ 921,070	$ (1,257,187)	$ (1,087,767)	$ 2,583,953	
19	Oregon Situs Resource True-Up	(7.1)	$ (4,969)	$ (7,019)	$ 13,618	$ (2,325)	$ (11,579)	$ (20,579)	$ (48,825)	$ (89,886)	$ (39,782)	$ (22,067)	$ (14,066)	$ (8,206)	$ (255,684)	
20	Total Monthly PCAM Differential - Above or (Below) Base	Line 18 + Line 19	$ 736,287	$ 83,772	$ (2,072,199)	$ (2,058,207)	$ (609,130)	$ (2,124,716)	$ 490,246	$ 5,664,498	$ 3,685,939	$ 899,003	$ (1,271,253)	$ (1,095,972)	$ 2,328,268	
21	Cumulative PCAM Differential - Above or (Below) base		$ 736,287	$ 820,059	$ (1,252,140)	$ (3,310,346)	$ (3,919,477)	$ (6,044,192)	$ (5,553,947)	$ 110,551	$ 3,796,490	$ 4,695,493	$ 3,424,241	$ 2,328,268		
22	Positive Deadband - ABOVE Base	Order. 12-493	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	$ 30,000,000	
23	Negative Deadband - BELOW Base	Order. 12-493	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	
24	Amount Deferrable - ABOVE Deadband		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
25	Amount Deferrable - BELOW Deadband		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
26	Total Incremental Deferrable	Line 24 + Line 25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
27	Total Incremental Deferral After 90%/10% Sharing Band	Line 26 * 90%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Balancing Account:																
28	Monthly Interest Rate	Note 1	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%		
29	Beginning Balance	Prior Month Line 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
30	Incremental Deferral	Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
31	Interest	Line 28 * (Line 29 + 50% x Line 30)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
32	**Ending Balance**	∑ Lines 29:31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Earnings Test:																
33	Earned Return on Equity	(9.1)													11.13%	
34	Allowed Return on Equity	UE 246													9.80%	
35	100bp ROE Revenue Requirement														$ 27,940,555	
36	Allowed Deferral After Earning Test														$ (9,354,883)	
37	**Total Deferred**														$ -	

Notes:
Note 1: 7.621% annual interest rate based on Oregon approved rate of return

ORDER NO. 18 449

Attachment A - Joint Stipulating Parties
Wilding-Gibbens-Jenks/1

APPENDIX A
Page 8 of 8

**PUBLIC UTILITY COMMISSION
OF OREGON**

UE 390

PACIFICORP

PAC/1605

Docket No. UE 361 Order No. 19-415

August 23, 2021

ORDER NO. 19-415

ENTERED: Nov 25 2019

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 361

In the Matter of PACIFICORP, dba PACIFIC POWER, 2018 Power Cost Adjustment Mechanism.	ORDER

DISPOSITION: STIPULATION ADOPTED; ADDITIONAL DIRECTIVE INCLUDED

I. SUMMARY

In this order, we adopt the parties' stipulated agreement that the 2018 actual power costs for PacifiCorp, dba Pacific Power, were within the deadband of the company's power cost adjustment mechanism (PCAM) and that there should be no change in customer rates. We also include a directive for party discussions, and for PacifiCorp to describe the discussions in its 2019 PCAM filing.

II. BACKGROUND

The PCAM is a true-up proceeding for net power costs (NPC). The PCAM compares PacifiCorp's actual NPC incurred in operations against the forecast NPC set in rates annually in PacifiCorp's Transition Adjustment Mechanism (TAM) proceeding. The PCAM allows PacifiCorp to recover or refund the difference between actual power costs and forecast power costs, subject to a deadband, a sharing mechanism, earnings test, and amortization cap.[1] This docket is PacifiCorp's sixth PCAM filing.[2]

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[1] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 14-15 (Dec 20, 2012) (establishing features of PacifiCorp's PCAM).
[2] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Power Cost Adjustment Mechanism*, Docket No. UE 290, Order No. 14-357 (Oct 16, 2014); *2014 Power Cost Adjustment Mechanism*, Docket No. UE 298, Order No. 15-380 (Nov 25, 2015); *2015 Power Cost Adjustment Mechanism*, Docket No. UE 309, Order No. 16-459 (Nov 30, 2016); *2016 Power Cost Adjustment Mechanism,* Docket No. UE 327, Order No. 17-524 (Dec 27, 2017*); 2017 Power Cost Adjustment Mechanism*, Docket No. UE 344, Order No. 18-449 (Nov 30, 2018) (all orders adopting stipulations, 2013 and 2014 PCAM filings resulted in no rate change due to the earnings test, and 2015, 2016, and 2017 PCAM filings resulted in no rate change due to the deadband).

The PCAM recovery parameters are first governed by the asymmetric deadband, which requires the company to absorb the NPC difference between negative $15 million and positive $30 million. If there is an amount that is above or below the deadband, it is subject to the sharing mechanism that allocates 90 percent to customers and 10 percent to the company. Next, the earning test provides that if PacifiCorp's earned return on equity (ROE) is within plus or minus 100 basis points of the allowed ROE, there is no recovery from or refund to customers. Recovery is allowed beyond the 100 basis point earning test deadband, up to an earnings level that is 100 basis points within the authorized ROE. The amortization cap provides that the amortization of deferred amounts are capped at 6 percent of the revenue for the preceding calendar year. Any rate adjustment after these calculations would be reflected in PacifiCorp's tariff Schedule 206.

III. PARTIES' FILING

PacifiCorp's initial PCAM filing shows 2018 actual NPC was above base costs by $19.1 million on an Oregon-allocated basis. PacifiCorp explains the steps and components of the PCAM calculation. PacifiCorp lists the Federal Energy Regulatory Commission (FERC) accounts that comprise NPC and the specific adjustments made to NPC to reflect ratemaking treatment of several items.

PacifiCorp states that its 2018 base power costs, set in the 2018 TAM in docket UE 323, were $25.90/MWh. PacifiCorp's initial PCAM filing shows that its actual 2018 power costs were $27.60/MWh. Thus, actual power costs were $1.70/MWh greater than the forecast.[3] Applying this differential to Oregon's retail load results in a $19.1 million cost on an Oregon-allocated basis. PacifiCorp's filing also shows the company's 2018 adjusted earned ROE is 8.67 percent, and its allowed ROE set in the 2012 rate case,[4] is 9.80 percent.[5]

In compliance with the parties' 2016 PCAM stipulation,[6] PacifiCorp's initial testimony describes any unusual expenses incurred over the course of 2018 and any large deviations of actual NPC from forecasted NPC. PacifiCorp states the main deviation in power costs was due to a decrease in wholesale sales revenues relative to the forecast. PacifiCorp states the actual wholesale market volumes were 46 percent less than forecast. The additional costs were partially offset by NPC savings relative to the forecast, with lower coal costs due to lower purchased coal volumes. Three additional categories provided smaller savings in 2018: (1) lower natural gas expense, (2) greater wind generation

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[3] PAC/100, Wilding/4.
[4] Order No. 12-493, Appendix A at 4.
[5] PAC/101, Wilding/1.
[6] Order No. 17-524 at 3-4.

resulting in greater Production Tax Credits, and (3) lower Energy Imbalance Market (EIM) costs.

PacifiCorp also explains how the Enbridge natural gas pipeline rupture and subsequent reduced pipeline capacity created a constraint at the Sumas gas hub from October 2018 through May 2019 when PacifiCorp filed its testimony. The constraint has contributed to higher electricity prices at the Mid-Columbia power market hub. PacifiCorp states that its Chehalis plant is sourced from the Sumas natural gas hub and the gas constraint and price spikes at Sumas have caused the Chehalis plant to be uneconomical at times or even unable to run.

The Oregon Citizens' Utility Board (CUB) and Alliance of Western Energy Consumers (AWEC) intervened in this docket. Prior to Staff and intervenor testimony, the parties held a settlement conference and reached an agreement resolving all issues in this docket. AWEC is not a signatory to the stipulation, but does not oppose the stipulation.

IV. STIPULATION

PacifiCorp, CUB, and Staff (stipulating parties) filed a stipulation and joint testimony in support of the stipulation. The stipulation is attached to this order as Appendix A. The stipulating parties analyzed PacifiCorp's PCAM filing and workpapers, and agree with PacifiCorp's calculations presented in PacifiCorp's initial filing.[7] The parties agree that PacifiCorp's PCAM calculation for 2018 complies with the PCAM parameters and results in no change to existing rates. The parties state the PCAM rate meets the fair and reasonable standard in ORS 756.040 and recommend we adopt the stipulation in its entirety.

V. DISCUSSION

We adopt the stipulation in its entirety. PacifiCorp's schedule 206 is currently set at zero from the 2017 PCAM, and because PacifiCorp's $19.1 million PCAM variance does not exceed the positive $30 million deadband, the schedule 206 rate will continue to be set at zero throughout 2020 to reflect the 2018 PCAM.

We reiterate our statement from last year's PCAM order that Staff, PacifiCorp, and intervenors may need to review future PCAM deferrals to ensure capital costs are not

[7] Stipulation at Attachment A.

included in the event the amounts deferred for the PCAM are amortized and put into rates.[8]

VI. ADDITIONAL DIRECTIVE

We continue to appreciate PacifiCorp's more detailed PCAM testimony. This requirement originated as Staff's request in the 2016 PCAM proceeding, was agreed to by PacifiCorp in the 2016 PCAM stipulation, memorialized in our 2016 PCAM order, and noted with appreciation in our 2017 PCAM order. Because the PCAM is filed just a few weeks after the company files its Results of Operations for the previous calendar year, PacifiCorp's PCAM testimony provides the most current docketed information on PacifiCorp's actual, incurred power costs.

We have stated that the expanded PCAM testimony provides a useful connection to the annual TAM process. Based on this value, we consider that integrating the PCAM testimony into PacifiCorp's annual TAM filing may be useful by ensuring the most current information on actual power costs informs the TAM forecast. We also recognize the timing of the filings is an issue and may make a combination filing impractical. Thus, we direct the stipulating parties to meet and discuss the feasibility, advantages and disadvantages of consolidating PacifiCorp's annual TAM and PCAM filings into one proceeding. PacifiCorp is to include a summary of the parties' discussions in its 2019 PCAM filing.

VII. ORDER

IT IS ORDERED that:

1. The stipulation between PacifiCorp, dba Pacific Power, the Staff of the Public Utility Commission of Oregon, and the Oregon Citizens' Utility Board, attached as Appendix A, is adopted.

2. PacifiCorp, dba, Pacific Power's Schedule 206 rates should continue to be at zero, effective January 1, 2020.

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[8] In docket UM 1909, we determined that we do not have authority to order deferrals of costs related to capital investments. *In the Matter of Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket No. UM 1909, Order No. 18-423 (Oct 29, 2018). We have opened an investigation, docketed as UM 2004, to explore the implications of that decision and address options to address recovery of capital costs consistent with our legal authority and the public interest.

3. PacifiCorp, dba, Pacific Power, shall include in its 2019 Power Cost Adjustment Mechanism filing a summary of parties' discussions on the feasibility, advantages and disadvantages of incorporating the Power Cost Adjustment Mechanism filing into the annual Transition Adjustment Mechanism proceeding.

Made, entered, and effective Nov 25 2019.

Megan W. Decker
Chair

Stephen M. Bloom
Commissioner

Letha Tawney
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.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 361

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2018 Power Cost Adjustment Mechanism	**STIPULATION**

INTRODUCTION

1. PacifiCorp d/b/a Pacific Power, Public Utility Commission of Oregon (Commission) Staff, and the Oregon Citizens' Utility Board (CUB) (collectively the Stipulating Parties) enter into this Stipulation to resolve all issues in docket UE 361, PacifiCorp's 2018 power cost adjustment mechanism (PCAM). The Alliance of Western Energy Consumers (AWEC) has intervened but is not signatory to this stipulation, however, AWEC does not oppose this stipulation. No other party has intervened in this proceeding.

BACKGROUND

2. The Commission approved PacifiCorp's PCAM in Order No. 12-493 in docket UE 246. The PCAM allows the recovery or refund of the difference between actual costs incurred to serve customers and the rates established in PacifiCorp's annual transition adjustment mechanism (TAM) filing. The amount recovered from or refunded to customers for a given year is subject to the following parameters:

- Asymmetrical Deadband – Any net power cost (NPC) difference between negative $15 million and positive $30 million is absorbed by the company.
- Sharing Mechanism – Any NPC difference above or below the deadband is shared 90 percent by customers and 10 percent by the company.

- Earnings Test – If the company's earned return on equity (ROE) is within plus or minus 100 basis points of the allowed ROE, there is no recovery from or refund to customers.
- Amortization Cap – The amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year.[1]

3. On May 15, 2019, PacifiCorp filed its PCAM for calendar year 2018. Attachment A to this Stipulation is a summary of the company's PCAM calculation. On an Oregon-allocated basis, actual PCAM costs exceeded base PCAM costs established in the 2018 TAM (Docket UE 323), by approximately $19.1 million.

4. After application of the deadband, there is no recovery for the 2018 PCAM.

5. The Stipulating Parties held a settlement conference on July 29, 2019. This conference resulted in an agreement resolving all issues in this docket.

AGREEMENT

6. The Stipulating Parties agree that PacifiCorp's PCAM calculation for calendar year 2018, as set forth in the company's initial filing and summarized above, complies with Order No. 12-493 and results in no change to existing rates.

7. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating Parties agree that this Stipulation will result in rates that meet the standard in ORS 756.040.

8. This Stipulation will be offered in to the record as evidence under OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and

[1] *In the Matter of PacifiCorp d/b/a Pacific Power's Request for a General Rate Revision*, Docket UE 246, Order No. 12-493 at 15 (Dec. 20, 2012).

any appeal, provide witnesses to sponsor the Stipulation at hearing, if required, and recommend that the Commission issue an order adopting the Stipulation.

9. The Stipulating 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 of the Stipulating Parties are entitled to withdraw from the Stipulation or exercise any other rights provided in OAR 860-001-0325(9). To withdraw from the Stipulation, a Stipulating Party must provide written notice to the Commission and the other Stipulating Parties within five days of service of the final order rejecting, modifying, or conditioning this Stipulation.

10. By entering into this Stipulation, no Settling Party approves, admits, or consents to the facts, principles, methods, or theories employed by any other Settling Party.

11. This Stipulation is not enforceable by any Settling Party unless and until adopted by the Commission in a final order. Each signatory to this Stipulation avers that they are signing this Stipulation in good faith and that they intend to abide by the terms of this Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Settling Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation. If the Commission rejects or modifies this Stipulation, the Settling Parties reserve the right to seek reconsideration or rehearing of the Commission order under ORS 756.561 and OAR 860-001-0720 or to appeal the Commission order under ORS 756.610.

12. This Stipulation may be executed in counterparts and each signed counterpart constitutes an original document.

This Stipulation is entered into by each Settling Party on the date entered below such Settling Party's signature.

PACIFICORP

By: ______________________

Date: September 9, 2019

STAFF of the PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

PACIFICCORP

By: ______________________________

Date: ______________________________

STAFF of the PUBLIC UTILITY COMMISSION OF OREGON

By: 054044
for Stephanie Andrus

Date: 9-9-19

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF of the PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: 9/10/19

ATTACHMENT A

Oregon Power Cost Adjustment Mechanism
January 1, 2018 - December 31, 2018
Attachment A - Power Cost Adjustment Mechanism Calculation

Line No.		Reference	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Actual:															
1	Total Company Adjusted Actual NPC	(2.1)	$ 121,926,980	$ 116,484,275	$ 120,443,189	$ 109,983,944	$ 107,102,701	$ 135,171,527	$ 199,837,850	$ 188,095,073	$ 125,381,451	$ 119,455,927	$ 122,775,130	$ 128,315,648	$ 1,594,973,694
2	Actual Allocated PTC	(4.1)	(9,817,338)	(8,010,095)	(6,806,363)	(6,818,701)	(3,135,677)	(4,059,875)	(2,820,558)	(3,306,793)	(3,704,143)	(4,864,130)	(6,987,690)	(7,654,905)	(67,986,269)
3	Actual EIM Costs	(5.1)	270,701	270,701	270,701	270,701	270,701	270,701	270,701	270,701	270,701	270,701	270,701	270,701	3,248,416
4	Actual Other Revenues	(6.1)	(1,067,523)	(1,228,634)	(1,033,533)	(1,016,877)	(866,342)	(917,836)	(756,278)	(873,792)	(774,223)	(721,761)	(949,472)	(984,974)	(11,191,246)
5	Total PCAM Adjusted Actual Costs	Sum Lines 1 - 4	111,312,820	107,516,247	112,873,994	102,419,067	103,371,383	130,464,517	196,531,715	184,185,189	121,173,786	114,140,738	115,108,668	119,946,471	1,519,044,596
6	Actual System Retail Load	(8.1)	4,679,407	4,180,523	4,325,158	4,083,879	4,282,507	4,737,662	5,550,557	5,121,109	4,401,376	4,275,097	4,446,091	4,958,110	55,041,477
7	Actual PCAM Costs $/MWH	Line 5 / Line 6	$ 23.79	$ 25.72	$ 26.10	$ 25.08	$ 24.14	$ 27.54	$ 35.41	$ 35.97	$ 27.53	$ 26.70	$ 25.89	$ 24.19	$ 27.60
Base:															
8	Total Company Base NPC	(3.1)	$ 128,200,948	$ 117,316,146	$ 120,728,957	$ 112,051,688	$ 118,238,124	$ 128,703,642	$ 145,100,787	$ 136,906,560	$ 119,165,738	$ 115,912,750	$ 115,537,372	$ 125,454,893	$ 1,483,317,604
9	Adjustment for Direct Access	(3.3)	(972,797)	(685,519)	(757,291)	(490,249)	(349,357)	(781,585)	(1,339,808)	(1,084,639)	(922,420)	(889,145)	(721,540)	(790,713)	(9,785,065)
10	Base Allocated PTC	(2.2)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(5,552,855)	(66,634,263)
11	Base EIM Costs	(3.4)	373,967	373,967	373,967	373,967	373,967	373,967	373,967	373,967	373,967	373,967	373,967	373,967	4,487,599
12	Base Other Revenues	(6.2)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(980,563)	(11,766,752)
13	Total PCAM Base Costs	Sum Lines 8 - 12	121,068,699	110,471,176	113,812,214	105,401,987	111,729,316	121,762,605	137,601,528	129,662,469	112,083,867	108,864,154	108,656,380	118,504,729	1,399,619,124
14	Base System Retail Load	(8.1)	4,821,206	4,287,440	4,363,025	4,098,706	4,282,717	4,484,513	5,123,039	4,917,807	4,330,167	4,233,900	4,308,957	4,786,649	54,038,127
15	Base PCAM Costs $/MWh	Line 8 / Line 14	$ 25.11	$ 25.77	$ 26.09	$ 25.72	$ 26.09	$ 27.15	$ 26.86	$ 26.37	$ 25.88	$ 25.71	$ 25.22	$ 24.76	$ 25.90
16	System PCAM Unit Cost Differential $/MWh	Line 7 - Line 15	$ (1.32)	$ (0.05)	$ 0.01	$ (0.64)	$ (1.95)	$ 0.39	$ 8.55	$ 9.60	$ 1.65	$ 0.99	$ 0.67	$ (0.57)	$ 1.70 #
17	Oregon Retail Load	(8.1)	1,154,791	1,112,096	1,088,764	993,821	953,744	1,012,409	1,170,588	1,127,070	943,769	977,627	1,082,144	1,250,410	12,867,233
Deferral:															
18	Monthly PCAM Differential - Above or (Below) Base	Line 16 * Line 17	$ (1,528,827)	$ (53,225)	$ 12,474	$ (633,111)	$ (1,860,148)	$ 390,733	$ 10,006,437	$ 10,819,835	$ 1,553,878	$ 964,409	$ 728,782	$ (706,947)	$ 19,694,290
19	Oregon Situs Resource True-Up	(7.1)	(5,566)	(9,415)	(16,474)	(31,548)	(7,934)	(36,805)	(186,288)	(150,955)	(35,847)	(55,039)	(51,629)	(33,863)	(621,364)
20	Total Monthly PCAM Differential - Above or (Below) Base	Line 18 + Line 19	(1,534,394)	(62,640)	(4,000)	(664,659)	(1,868,082)	353,928	9,820,150	10,668,879	1,518,030	909,370	677,153	(740,810)	19,072,926
21	Cumulative PCAM Differential - Above or (Below) base		(1,534,394)	(1,597,033)	(1,601,034)	(2,265,692)	(4,133,774)	(3,779,846)	6,040,303	16,709,182	18,227,213	19,136,583	19,813,736	19,072,926	
22	Positive Deadband - ABOVE Base	Order. 12-493	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
23	Negative Deadband - BELOW Base	Order. 12-493	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)
24	Amount Deferrable - ABOVE Deadband		-	-	-	-	-	-	-	-	-	-	-	-	-
25	Amount Deferrable - BELOW Deadband		-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Incremental Deferrable	Line 24 + Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Incremental Deferral After 90%/10% Sharing Band	Line 26 * 90%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Balancing Account:															
28	Monthly Interest Rate	Note 1	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	
29	Beginning Balance	Prior Month Line 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Incremental Deferral	Line 27	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Interest	Line 28 * (Line 29 + 50% x Line 30)	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Ending Balance	∑ Lines 29:31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Earnings Test:															
33	Earned Return on Equity	(9.1)													8.67%
34	Allowed Return on Equity	UE 246													9.80%
35	100bp ROE Revenue Requirement														$ 23,548,943
36	Allowed Deferral After Earning Test														3,172,191
37	Total Deferred														$ -

Notes:

Note 1: 7.621% annual interest rate based on Oregon approved rate of return

PUBLIC UTILITY COMMISSION
OF OREGON

UE 390

PACIFICORP

PAC/1606

Docket No. UE 379 Order No. 20-489

August 23, 2021

ORDER NO. 20-489

ENTERED: Dec 29 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 379

In the Matter of PACIFICORP, dba PACIFIC POWER, 2019 Power Cost Adjustment Mechanism.	ORDER

DISPOSITION: STIPULATION ADOPTED

I. SUMMARY

In this order, we adopt the parties' stipulated agreement that PacifiCorp, dba Pacific Power's 2019 net power cost variance results in no change to customer rates because of the earnings test in the power cost adjustment mechanism (PCAM).

II. BACKGROUND

The PCAM is a true-up proceeding for net power costs (NPC). The PCAM compares PacifiCorp's actual NPC incurred in operations against the forecast NPC set in rates annually in PacifiCorp's Transition Adjustment Mechanism (TAM) proceeding. The PCAM allows PacifiCorp to recover or refund the difference between actual power costs and forecast power costs, subject to a deadband, a sharing mechanism, earnings test, and amortization cap.[1] This docket is PacifiCorp's seventh PCAM filing.[2]

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[1] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 14-15 (Dec 20, 2012) (establishing features of PacifiCorp's PCAM).

[2] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Power Cost Adjustment Mechanism*, Docket No. UE 290, Order No. 14-357 (Oct 16, 2014); *2014 Power Cost Adjustment Mechanism*, Docket No. UE 298, Order No. 15-380 (Nov 25, 2015); *2015 Power Cost Adjustment Mechanism*, Docket No. UE 309, Order No. 16-459 (Nov 30, 2016); *2016 Power Cost Adjustment Mechanism,* Docket No. UE 327, Order No. 17-524 (Dec 27, 2017); *2017 Power Cost Adjustment Mechanism*, Docket No. UE 344, Order No. 18-449 (Nov 30, 2018); *2018 Power Cost Adjustment Mechanism*, Docket No. UE 361, Order No. 19-415 (Nov 25, 2019) (all orders adopting stipulations, 2013 and 2014 PCAM filings resulted in no rate change due to the earnings test, and 2015, 2016, and 2017 PCAM filings resulted in no rate change due to the deadband).

The PCAM recovery parameters are first governed by the asymmetric deadband, which requires the company to absorb the NPC difference between negative \$15 million and positive \$30 million. If there is an amount that is above or below the deadband, it is subject to the sharing mechanism that allocates 90 percent to customers and 10 percent to the company. Next, the earning test provides that if PacifiCorp's earned return on equity (ROE) is within plus or minus 100 basis points of its allowed ROE, there is no recovery from or refund to customers. Recovery is allowed beyond the 100 basis point earning test deadband, up to an earnings level that is 100 basis points within the authorized ROE. The amortization cap provides that the amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year. Any rate adjustment after these calculations would be reflected in PacifiCorp's tariff Schedule 206.

III. PARTIES' FILINGS

PacifiCorp's initial PCAM filing explains that on an Oregon-allocated basis, actual PCAM costs were \$45.1 million more than base costs established in the 2019 TAM in docket UE 339. PacifiCorp states that while the amounts exceed the established deadband by \$15.1 million, PacifiCorp's earned return on equity (ROE) for 2019 is 9.34 percent which is within 100 basis points of PacifiCorp's 2019 authorized ROE of 9.8 percent. PacifiCorp states that because Schedule 206, Power Cost Adjustment Mechanism Adjustment, is currently set at zero cents per kilowatt hour, no tariff change is required at this time.

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. The additional costs were partially offset by NPC savings relative to the forecast, with lower coal and natural gas costs due to lower generation levels.

The Oregon Citizens' Utility Board (CUB) and Alliance of Western Energy Consumers (AWEC) intervened in this docket. Prior to Staff and intervenor testimony, the parties reached an agreement resolving all issues. AWEC is not a signatory to the stipulation, but does not oppose the stipulation.

PacifiCorp, CUB, and Staff (stipulating parties) filed a stipulation and joint testimony in support of the stipulation. The stipulation and the PCAM calculation are attached to this order as Appendix A. The stipulating parties analyzed PacifiCorp's PCAM filing and workpapers, and agree with PacifiCorp's calculations presented in PacifiCorp's initial filing.[3] The parties agree that PacifiCorp's PCAM calculation for 2019 complies with the PCAM parameters and results in no change to existing rates. The parties request we adopt the stipulation.

IV. DISCUSSION

We adopt the stipulation in its entirety. In 2019, PacifiCorp's actual PCAM costs exceeded base cost by $45.1 million. Although this variance exceeds the positive $30 million PCAM deadband, there is no change to rates because of the earnings test. PacifiCorp's earned ROE for 2019 was 9.34 percent which is within 100 basis points of its authorized ROE of 9.8 percent. Thus, PacifiCorp's 2019 PCAM results in no change to rates and the Schedule 206 rate will continue to be set at zero throughout 2021 to reflect the 2019 PCAM.

V. ORDER

IT IS ORDERED that:

1. The stipulation between PacifiCorp, dba Pacific Power, Staff of the Public Utility Commission of Oregon, and the Oregon Citizens' Utility Board, attached as Appendix A, is adopted.

2. PacifiCorp, dba, Pacific Power's Schedule 206 rates should continue to be at zero, effective January 1, 2021.

Made, entered, and effective Dec 29 2020.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

[3] Stipulation at Attachment A.

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.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 379

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2019 Power Cost Adjustment Mechanism	**STIPULATION**

INTRODUCTION

1. PacifiCorp d/b/a Pacific Power, Public Utility Commission of Oregon (Commission) Staff, and the Oregon Citizens' Utility Board (CUB) (collectively the Stipulating Parties) enter into this Stipulation to resolve all issues in docket UE 379, PacifiCorp's 2019 power cost adjustment mechanism (PCAM). The Alliance of Western Energy Consumers (AWEC) has intervened but is not signatory to this stipulation, however, AWEC does not oppose this stipulation. No other party has intervened in this proceeding.

BACKGROUND

2. The Commission approved PacifiCorp's PCAM in Order No. 12-493 in docket UE 246. The PCAM allows the recovery or refund of the difference between actual costs incurred to serve customers and the rates established in PacifiCorp's annual transition adjustment mechanism (TAM) filing. The amount recovered from or refunded to customers for a given year is subject to the following parameters:

- Asymmetrical Deadband – Any net power cost (NPC) difference between negative $15 million and positive $30 million is absorbed by the company.
- Sharing Mechanism – Any NPC difference above or below the deadband is shared 90 percent by customers and 10 percent by the company.

- Earnings Test – If the company's earned return on equity (ROE) is within plus or minus 100 basis points of the allowed ROE, there is no recovery from or refund to customers.
- Amortization Cap – The amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year.[1]

3. On May 15, 2020, PacifiCorp filed its PCAM for calendar year 2019. Attachment A to this Stipulation is a summary of the company's PCAM calculation. On an Oregon-allocated basis, actual PCAM costs exceeded base PCAM costs established in the 2019 TAM (Docket UE 339), by approximately $45.1 million.

4. Although the $45.1 million exceeds the deadband, after application of the earnings test, there is no recovery for the 2019 PCAM.

5. The Stipulating Parties communicated via email beginning in July, 2020. These communications resulted in an agreement that no rate change is appropriate in this docket.[2]

AGREEMENT

6. The Stipulating Parties agree that PacifiCorp's PCAM calculation for calendar year 2019, as set forth in the company's initial filing and summarized above, complies with Order No. 12-493 and results in no change to existing rates.

7. The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating Parties agree that this Stipulation will result in rates that meet the standard in ORS 756.040.

[1] *In the Matter of PacifiCorp d/b/a Pacific Power's Request for a General Rate Revision*, Docket UE 246, Order No. 12-493 at 15 (Dec. 20, 2012).
[2] Staff notes that there is an open issue regarding the treatment of actual wind generation for Energy Vision 2020 repowered and new wind projects in the PCAM proceeding, as set forth in the record in OPUC Docket No. UE 374, which this stipulation does not resolve. However, Staff is not seeking Commission resolution of this issue in this case.

8. This Stipulation will be offered in the record as evidence under OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor the Stipulation at hearing, if required, and recommend that the Commission issue an order adopting the Stipulation.

9. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. The Stipulating Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, the Parties will meet in good faith within fifteen days and discuss next steps. A Party may withdraw from the Stipulation after this meeting by providing written notice to the Commission and other Parties. Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

10. By entering into this Stipulation, no Settling Party approves, admits, or consents to the facts, principles, methods, or theories employed by any other Settling Party.

11. This Stipulation is not enforceable by any Settling Party unless and until adopted by the Commission in a final order. Each signatory to this Stipulation avers that they are signing this Stipulation in good faith and that they intend to abide by the terms of this Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Settling Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation. If the Commission rejects or modifies this Stipulation, the Settling Parties reserve the right to

seek reconsideration or rehearing of the Commission order under ORS 756.561 and OAR 860-001-0720 or to appeal the Commission order under ORS 756.610.

12. This Stipulation may be executed in counterparts and each signed counterpart constitutes an original document.

This Stipulation is entered into by each Settling Party on the date entered below such Settling Party's signature.

PACIFICORP	STAFF of the PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
Date: 9/30/2020	Date: ______________________
OREGON CITIZENS' UTILITY BOARD	
By: ______________________	
Date: ______________________	

seek reconsideration or rehearing of the Commission order under ORS 756.561 and OAR 860-001-0720 or to appeal the Commission order under ORS 756.610.

12. This Stipulation may be executed in counterparts and each signed counterpart constitutes an original document.

This Stipulation is entered into by each Settling Party on the date entered below such Settling Party's signature.

PACIFICORP	STAFF of the PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: /s/ Sommer Moser
Date: ______________________	Date: 9/30/2020
OREGON CITIZENS' UTILITY BOARD	
By: ______________________	
Date: ______________________	

seek reconsideration or rehearing of the Commission order under ORS 756.561 and OAR 860-001-0720 or to appeal the Commission order under ORS 756.610.

12. This Stipulation may be executed in counterparts and each signed counterpart constitutes an original document.

This Stipulation is entered into by each Settling Party on the date entered below such Settling Party's signature.

PACIFICORP

By: ________________________________

Date: ______________________________

STAFF of the PUBLIC UTILITY COMMISSION OF OREGON

By: ________________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ________________________________

Date: 9/30/20

ATTACHMENT A

Oregon Power Cost Adjustment Mechanism
January 1, 2019 - December 31, 2019
Attachment A - Power Cost Adjustment Mechanism Calculation

Line No.		Reference	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Actual:															
1	Total Company Adjusted Actual NPC	(2.1)	$ 131,540,281	$ 165,154,527	$ 136,294,942	$ 107,602,901	$ 112,620,252	$ 124,164,655	$ 167,860,313	$ 177,632,068	$ 152,222,400	$ 126,774,673	$ 124,909,292	$ 129,351,204	$ 1,656,127,508
2	Actual Allocated PTC	(4.1)	(3,487,444)	(2,951,365)	(1,816,786)	(2,536,684)	(1,780,817)	(1,345,285)	(1,073,516)	(1,161,531)	(2,294,136)	(5,116,609)	(5,175,044)	(7,474,271)	(36,213,490)
3	Actual EIM Costs	(5.1)	223,975	223,975	223,975	223,975	223,975	223,975	223,975	223,975	223,975	223,975	223,975	223,975	2,687,695
4	Actual Other Revenues	(6.1)	(761,558)	(637,191)	(635,506)	(1,084,085)	(877,447)	(1,028,624)	(989,101)	(855,439)	(930,079)	(922,779)	(640,797)	(696,289)	(10,058,895)
5	Total PCAM Adjusted Actual Costs	Sum Lines 1 - 4	127,515,254	161,789,945	134,066,625	104,206,106	110,185,962	122,014,720	166,021,670	175,839,073	149,222,159	120,959,259	119,317,425	121,404,618	1,612,542,818
6	Actual System Retail Load	(8.1)	4,799,736	4,474,747	4,479,477	4,083,700	4,234,177	4,582,946	5,288,590	5,153,136	4,404,692	4,431,700	4,434,088	4,936,316	55,303,306
7	Actual PCAM Costs $/MWH	Line 5 / Line 6	$ 26.57	$ 36.16	$ 29.93	$ 25.52	$ 26.02	$ 26.62	$ 31.39	$ 34.12	$ 33.88	$ 27.29	$ 26.91	$ 24.59	$ 29.16
Base:															
8	Total Company Base NPC	(3.1)	$ 124,011,813	$ 115,143,234	$ 120,747,988	$ 107,182,649	$ 113,237,311	$ 120,861,832	$ 152,621,725	$ 143,627,146	$ 112,462,222	$ 108,902,959	$ 111,519,174	$ 121,770,203	$ 1,452,088,256
9	Adjustment for Direct Access	(3.3)	(1,215,147)	(1,125,682)	(934,060)	(588,545)	(321,443)	(688,170)	(1,387,038)	(1,335,521)	(827,099)	(734,577)	(697,591)	(669,223)	(10,524,095)
10	Base Allocated PTC	(2.2)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(3,122,145)	(37,465,734)
11	Base EIM Costs	(3.4)	232,182	232,182	232,182	232,182	232,182	232,182	232,182	232,182	232,182	232,182	232,182	232,182	2,786,190
12	Base Other Revenues	(6.2)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(997,601)	(11,971,208)
13	Total PCAM Base Costs	Sum Lines 8 - 12	118,909,103	110,129,989	115,926,365	102,706,542	109,028,305	116,286,100	147,347,124	138,404,062	107,747,561	104,280,820	106,934,020	117,213,417	1,394,913,409
14	Base System Retail Load	(8.1)	4,851,164	4,220,608	4,377,254	4,113,656	4,295,331	4,473,053	5,148,822	4,931,687	4,319,834	4,253,283	4,378,320	4,861,392	54,224,405
15	Base PCAM Costs $/MWh	Line 8 / Line 14	$ 24.51	$ 26.09	$ 26.48	$ 24.97	$ 25.38	$ 26.00	$ 28.62	$ 28.06	$ 24.94	$ 24.52	$ 24.42	$ 24.11	$ 25.72
16	System PCAM Unit Cost Differential $/MWh	Line 7 - Line 15	$ 2.06	$ 10.06	$ 3.45	$ 0.55	$ 0.64	$ 0.63	$ 2.77	$ 6.06	$ 8.94	$ 2.78	$ 2.49	$ 0.48	$ 3.43 #
17	Oregon Retail Load	(8.1)	1,205,721	1,191,205	1,128,880	958,561	966,202	993,709	1,098,239	1,142,671	979,445	1,053,953	1,102,892	1,267,185	13,088,664
Deferral:															
18	Monthly PCAM Differential - Above or (Below) Base	Line 16 * Line 17	$ 2,478,580	$ 11,986,891	$ 3,889,291	$ 527,549	$ 618,380	$ 622,671	$ 3,047,382	$ 6,922,857	$ 8,751,815	$ 2,926,172	$ 2,741,345	$ 612,170	$ 45,125,103
19	Oregon Situs Resource True-Up	(7.1)	14,200	(29,408)	(71,229)	(10,465)	1,295	6,077	41,785	54,723	11,303	616	689	(2,626)	16,958
20	Total Monthly PCAM Differential - Above or (Below) Base	Line 18 + Line 19	2,492,780	11,957,482	3,818,062	517,084	619,675	628,748	3,089,167	6,977,580	8,763,118	2,926,788	2,742,035	609,544	45,142,061
21	Cumulative PCAM Differential - Above or (Below) base		2,492,780	14,450,262	18,268,324	18,785,408	19,405,083	20,033,831	23,122,997	30,100,577	38,863,695	41,790,483	44,532,517	45,142,061	
22	Positive Deadband - ABOVE Base	Order. 12-493	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
23	Negative Deadband - BELOW Base	Order. 12-493	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)
24	Amount Deferrable - ABOVE Deadband		-	-	-	-	-	-	-	100,577	8,763,118	2,926,788	2,742,035	609,544	15,142,061
25	Amount Deferrable - BELOW Deadband		-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Incremental Deferrable	Line 24 + Line 25	-	-	-	-	-	-	-	100,577	8,763,118	2,926,788	2,742,035	609,544	15,142,061
27	Total Incremental Deferral After 90%/10% Sharing Band	Line 26 * 90%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,519	$ 7,886,806	$ 2,634,109	$ 2,467,831	$ 548,590	$ 13,627,855
Energy Balancing Account:															
28	Monthly Interest Rate	Note 1	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	
29	Beginning Balance	Prior Month Line 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,807	$ 8,003,233	$ 10,696,534	$ 13,240,133	$ -
30	Incremental Deferral	Line 27	-	-	-	-	-	-	-	90,519	7,886,806	2,634,109	2,467,831	548,590	13,627,855
31	Interest	Line 28 * (Line 29 + 50% x Line 30)	-	-	-	-	-	-	-	287	25,621	59,192	75,768	85,828	246,696
32	Ending Balance	∑ Lines 29:31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,807	$ 8,003,233	$ 10,696,534	$ 13,240,133	$ 13,874,551	$ 13,874,551
Earnings Test:															
33	Earned Return on Equity	(9.1)													9.34%
34	Allowed Return on Equity	UE 246													9.80%
35	100bp ROE Revenue Requirement														$ 23,833,022
36	Allowed Deferral After Earning Test														-
37	Total Deferred														$ -

Notes:
Note 1: 7.621% annual interest rate based on Oregon approved rate of return

ORDER NO. 20-489

APPENDIX A
8 of 17

Docket No. UE 379
Joint Stipulating Parties/100
Witnesses: Webb-Gibbens-Jenks

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Stipulating Parties' Joint Testimony of
David G. Webb, Scott Gibbens, and Bob Jenks

September 2020

TABLE OF CONTENTS

Joint Testimony Supporting Stipulation 1

Q. Please state your names, business addresses, and present positions.

A. My name is David G. Webb. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs. My witness qualifications are set forth in PAC/100, Webb/1.

My name is Scott Gibbens. My business address is 201 High Street SE, Suite 100, Salem Oregon 97301. I am employed as a Senior Economist in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (Commission). My Witness Qualification Statement is found in Exhibit Joint Stipulating Parties/101.

My name is Bob Jenks. My business address is 610 SW Broadway, Suite 400, Portland, Oregon 97205. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My Witness Qualification Statement is found in Exhibit Joint Stipulating Parties/102.

JOINT TESTIMONY SUPPORTING STIPULATION

Q. What is the purpose of this Joint Testimony?

A. Commission Staff, PacifiCorp, and CUB, collectively the Stipulating Parties, jointly provide this testimony in support of the Stipulation, filed concurrent with this Joint Testimony. The Stipulating Parties request that the Commission issue an order approving the Stipulation and implementing its terms.

Q. Which parties to docket UE 379 have joined in the Stipulation?

A. All parties to docket UE 379 agreed that PacifiCorp's actual net power costs (NPC) would not result in a change in rates to customers. After settlement communications, Staff, CUB and PacifiCorp executed the Stipulation on

September 29, 2020. The Alliance of Western Energy Consumers (AWEC) has intervened but is not signatory to this stipulation, however, AWEC does not oppose this stipulation. No other party has intervened in this proceeding.

Q. Does the Stipulation provide resolution that no rate change should occur in docket UE 379?

A. Yes. The Stipulating Parties agree that the company's power cost adjustment mechanism (PCAM) for calendar year 2019, as set forth in its initial filing, complies with Order No. 12-493 and results in no change to PacifiCorp's rates. The Stipulation does not resolve whether for purposes of the PCAM, actual wind generation for PacifiCorp's EV 2020 repowered and new wind projects should be adjusted to match the forecasted wind generation from the TAM. However, this issue has no impact on the outcome in this case. As such, Commission approval of the Stipulation will result in just and reasonable rates and an efficient resolution of this proceeding.

Q. What is the purpose of PacifiCorp's PCAM?

A. In Order No. 12-493, the Commission approved a PCAM to allow PacifiCorp to recover the difference between actual NPC incurred to serve customers and the base NPC established in the company's annual transition adjustment mechanism (TAM) filing. The amount received from or refunded to customers for a given year is subject to deadbands, sharing bands, an earnings test, and an amortization cap.[1] PacifiCorp filed its 2019 PCAM for calendar year 2019, on May 15, 2020.

[1] *In the Matter of PacifiCorp d/b/a Pacific Power's Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 15 (Dec. 20, 2012).

Q. What was the variance between actual PCAM costs and base PCAM costs for calendar year 2019?

A. The actual PCAM costs exceeded base PCAM costs for calendar year 2019 by approximately $45.1 million on an Oregon allocated basis.

Q. Did the PCAM variance exceed the deadband for 2019?

A. Yes.

Q. Did PacifiCorp meet the PCAM earnings test parameters for 2019?

A. No. PacifiCorp's earned return on equity (ROE) for 2019 was 9.34 percent which is below PacifiCorp's authorized ROE of 9.8 percent, but still within 100 basis points of the authorized ROE. Therefore PacifiCorp does not meet the requirements of the earnings test for the PCAM.

Q. What is the rate impact resulting from the 2019 PCAM?

A. After the application of the earnings test identified in Order No. 12-493, PacifiCorp's 2019 PCAM results in no change to rates.

Q. Does this conclude your joint stipulating parties testimony?

A. Yes.

Docket No. UE 379
Joint Stipulating Parties/101
Witnesses: Webb-Gibbens-Jenks

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Joint Testimony

Witness Qualifications of Scott Gibbens

September 2020

Docket No. UE 379

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

Docket No. UE 379
Joint Stipulating Parties/102
Witnesses: Webb-Gibbens-Jenks

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Joint Testimony

Witness Qualifications of Bob Jenks

September 2020

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

PUBLIC UTILITY COMMISSION
OF OREGON

UE 390

PACIFICORP

PAC/1607

Docket No. UE 392 Letter and excerpt from PAC/100 Direct Testimony of Jack Painter

August 23, 2021

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

May 17, 2021

VIA ELECTRONIC FILING

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

RE: UE 392—PacifiCorp's 2020 Power Cost Adjustment Mechanism

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) encloses for electronic filing its 2020 Power Cost Adjustment Mechanism (PCAM) filing.

In Order No. 12-493, the Public Utility Commission of Oregon (Commission) approved a PCAM to allow PacifiCorp to recover the difference between actual net power costs (NPC) incurred to serve customers and the base NPC established in PacifiCorp's annual transition adjustment mechanism (TAM) filing. The amount recovered from or refunded to customers for a given year is subject to the following parameters:

- Asymmetrical Deadband. Any variance between negative $15 million and positive $30 million will be absorbed by the Company.
- Sharing Band. Any variance above or below the deadband will be shared 90 percent by customers and 10 percent by the Company.
- Earnings Test. If PacifiCorp's earned return on equity (ROE) is within plus or minus 100 basis points of the allowed ROE, there will be no recovery from or refund to customers.
- Amortization Cap. The amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year.

On an Oregon-allocated basis, actual PCAM costs were $29.5 million more than base PCAM costs established in the 2020 TAM (docket UE 356). The application of the deadband results in no recovery through the 2020 PCAM. Therefore PacifiCorp is not requesting a rate change. Because Schedule 206, Power Cost Adjustment Mechanism – Adjustment, is currently set at zero cents per kilowatt hour for all schedules, no tariff change is required at this time.

In compliance with Order No. 17-524, PacifiCorp includes supporting direct testimony of Jack Painter that includes a discussion of any unusual expenses incurred over the course of the 2020 PCAM year and large deviations of actual NPC from forecasted NPC. A differential worksheet indicating actual minus base power costs for each separate cost category in the PCAM on a gross cost and per megawatt-hour unit basis is included in the confidential workpapers accompanying this filing.

UE 392
Public Utility Commission of Oregon
May 17, 2021
Page 2

Confidential material supporting this filing is provided under Order No. 21-148.

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

Oregon Dockets PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, OR 97232 oregondockets@pacificorp.com	Ajay Kumar State Regulatory Attorney 825 NE Multnomah Street, Suite 2000 Portland, OR 97232 Ajay.kumar@pacificorp.com

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

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Cathie Allen at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director of Regulation

cc: Service List UE 374
Service List UE 379

Docket No. UE 392
Exhibit PAC/100
Witness: Jack Painter

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Jack Painter

May 2021

V. SUMMARY OF THE NPC DIFFERENCES

Q. Please describe the Base NPC PacifiCorp used to calculate the NPC component of the PCAM deferral.

A. The Base NPC for the 2020 PCAM was set in Order No. 19-351 in docket UE 356. Base rates became effective January 1, 2020, with additional rate changes on April 1, 2020, September 18, 2020, and December 11, 2020, due to the addition of Company-owned wind resources and PTCs.

Q. Please describe Table 2 and the line items making up the difference between Actual NPC and Base NPC.

A. Table 2 displays the Base NPC approved by the Commission for the Deferral Period. The remainder of Table 2 is a breakout of the difference between Actual NPC and Base NPC, by cost category, on a total-company basis. The differences by category in Table 2 result from comparing Actual NPC to the Base NPC effective during the Deferral Period.

Table 3
Net Power Cost Reconciliation ($millions)

Base NPC	$	1,434
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		257
Purchased Power Expense		(84)
Coal Fuel Expense		(55)
Natural Gas Expense		(45)
Wheeling, Hydro and Other Expense		14
Total Increase/(Decrease)		87
Adjusted Actual NPC	$	1,521

Q. Please describe the differences between Actual NPC and Base NPC.

A. Actual NPC were $87 million higher than Base NPC due to a $257 million decrease in wholesale sales revenues (which increases NPC) and a $14 million increase in wheeling and other expenses. The reduction in wholesale sales revenue was partially offset by an $84 million reduction in purchased power expenses, a $55 million reduction in coal fuel expense, and a $45 million reduction in natural gas expense.

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales revenues were lower relative to Base NPC due to a reduction in wholesale sales volume of market transactions (represented in PacifiCorp's production model (GRID) as short-term firm and system balancing sales). Revenue from market transactions was approximately $256 million lower than Base NPC and the average price of actual market sales transactions was $4.50/MWh, or 15 percent, higher than average price in Base NPC. Actual wholesale market volumes were 9,114 gigawatt-hours (GWh), or 66 percent, lower than Base NPC.

Q. Is the variance in actual wholesale sales revenue relative to the base partially attributable to the modeling of market capacity limits in the TAM?

A. Yes. As explained in the testimony of Company witness Mr. David G. Webb for the 2022 TAM in docket UE 390, the market capacity limits that were used in the 2020 TAM have caused the wholesale sales revenue to be over forecast. As proposed in the 2022 TAM, PacifiCorp has revised the forecast methodology to base wholesale sales market caps on the four-year historical average instead of the maximum of each month for the last four years. This approach will help improve the forecast of wholesale sales, ultimately reducing the variance between Base and Actual NPC.

Q. Please explain the changes in purchased power expense.

A. Purchased power expense decreased primarily due to lower market purchases of $46 million (represented in GRID as short-term firm and system balancing purchases). Actual market purchases were 4,853 GWh, or 56 percent, lower than Base NPC and the average price of actual market purchase transactions was $15.91/MWh, or 72 percent, higher than Base NPC.

Q. Please explain the changes in coal fuel expense.

A. Coal fuel expense decreased because coal generation volume decreased 2,169 GWh, or seven percent, compared to Base NPC. The average cost of coal generation also decreased from $20.90/MWh in Base NPC to $20.60/MWh in the Deferral Period.

Q. Please explain the changes in natural gas fuel expense.

A. The total natural gas fuel expense in Actual NPC decreased by $45 million compared to Base NPC mainly due to a decrease in natural gas generation volume of 3,878 GWh, or 24 percent lower than Base NPC during the Deferral Period.

VI. IMPACT OF PARTICIPATING IN THE EIM

Q. Are the actual benefits from participating in the EIM with CAISO included in the PCAM deferral?

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. The Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. The Company's EIM inter-regional benefit for the deferral period was approximately $46.8 million.

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

PACIFICORP

PAC/1608

Docket No. UE 375 AWEC/100 Opening Testimony of Bradley G. Mullins

August 23, 2021

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 375

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2021 Transition Adjustment Mechanism.	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

May 15, 2020

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EXHIBIT LIST

AWEC/101 - Qualification Statement of Bradley G. Mullins

AWEC/102 - PacifiCorp Responses to Discovery Requests

AWEC/103 - EV 2020 Modeling Assumptions

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 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 electrical services from PacifiCorp dba Pacific Power ("PacifiCorp" or "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's proposed Net Variable Power Costs ("NVPC") update and present several adjustments to PacifiCorp's proposed Generation and Regulation Initiative Decision Tools ("GRID") model. Given that this Transition Adjustment Mechanism ("TAM") is being conducted in conjunction with a general rate case, I also discuss making changes to the direct access program.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I performed a limited review of PacifiCorp's filing and conducted a single round of discovery. My review was not comprehensive, so it is possible there are other necessary adjustments that I was not able to document and quantify in time for filing this testimony.

Q. PLEASE SUMMARIZE YOUR PROPOSED MODELING ADJUSTMENTS.

A. The estimated impacts of my recommended modeling adjustments are shown in Table 1, below.

Table 1
Estimated Impact of Proposed Modeling Adjustments
($000,000)

	Total Company	OR
PacifiCorp Filing	1,400.9	356.6
Adjustments		
EV 2020 EIM Link	8.3	2.2
EV 2020 Line Loss Benefits	2.5	0.7
EV 2020 Reliability Benefits	4.3	1.1
Gas Optimization	1.0	0.3
Monthly Price Forecast	32.3	8.2
BCC Plant additions	0.3	0.1
BCC Remediation Trust	16.3	4.1
Total Adjustments	65.0	16.6
Adjusted	1,335.9	340.0

II. ENERGY VISION 2020 BENEFITS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO EV 2020.

A. I recommend making the following three modeling changes in conjunction with the Energy Vision ("EV") 2020:

1) Including a virtual 300 MW transmission link in the GRID model between the Jim Bridger transmission area to the Walla Walla transmission area;
2) Including transmission line loss savings of 11.6 aMW in the GRID model; and,
3) Incorporating 36.5 aMW of transfer capability to account for improved transmission reliability.

These adjustments are necessary to conform PacifiCorp's forecasting in this docket to the forecasting that was used when PacifiCorp made the economic case to acquire the EV 2020 wind and transmission assets. These modeling assumption values were applied when PacifiCorp forecast the net power cost benefits associated with EV 2020 in the 2017 IRP and 2017R RFP. The assumptions were not, however, applied in the forecast used for this ratemaking proceeding. It is not reasonable for PacifiCorp to forecast the benefits of the EV 2020 assets for ratemaking purposes in a manner that is inconsistent with the forecast used to justify the assets. Accordingly, excluding the benefits associated with the above modeling adjustments in this proceeding is not reasonable.

Q. HOW DO YOU KNOW THAT PACIFICORP USED THESE MODELING TECHNIQUES IN ITS 2017 IRP AND 2017R RFP?

A. In Docket No. UE 339, Exhibit AWEC/102, PacifiCorp confirmed use of the 300 MW energy imbalance market ("EIM") link in the 2017R Request for Proposal ("RFP") process. In the response, PacifiCorp also confirmed application of 11.6 aMW of line loss savings, and 36.5 aMW of reliability benefits in the 2017R RFP process. I have attached that response as Exhibit AWEC/103.

Q. HAVE THESE ADJUSTMENTS BEEN ADOPTED IN PAST TAM FILINGS?

A. Yes. In Docket No. UE 339, PacifiCorp agreed to a monetary adjustment for the 300 MW link. In this proceeding, however, PacifiCorp has not modeled the 300 MW link in the GRID model. The other two adjustments were not applicable in past dockets, since the underlying transmission facilities had not been built. This is the first proceeding where the transmission benefits have been at issue.

Q. PLEASE PROVIDE BACKGROUND ON THE EV 2020 ASSETS.

A. Energy Vision 2020 was a project originally identified in PacifiCorp's 2017 Integrated Resource Plan[1/] and procured in PacifiCorp's 2017R RFP.[2/] It included 860 MW of new wind resources (collectively, "Wind Projects") and a new high voltage transmission line between the Aeolus and Bridger/Anticline substations, including associated network upgrades (the "Transmission Projects"). The total cost of the project was $1.9 billion.

Q. DID THE COMMISSION ACKNOWLEDGE THE 2017 IRP?

A. Yes. In Docket No. LC 67, the Commission acknowledged the 2017 IRP with Conditions and Modifications.[3/] Parties were concerned the assets were being justified on the basis of economic benefits, rather than an impending capacity shortfall. Responding to these concerns, the Commission imposed an express condition: "We intend to ensure that customer risk exposure is mitigated appropriately, and recovery may be structured to hold PacifiCorp to the cost and benefit projections in its analysis."[4/]

a. <u>300 MW Link Jim Bridger - Walla Walla</u>

Q. PLEASE DISCUSS THE VIRTUAL 300 MW LINK BETWEEN JIM BRIDGER AND WALLA WALLA ASSUMED IN THE 2017R RFP.

A. The modeling for this transmission link was described on page 13 of PacifiCorp's July 28, 2017 IRP Informational Filing with the Commission in Docket No. LC 67:

> In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the Energy Imbalance Market (EIM) can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing

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1/ Docket No. LC. 67, PacifiCorp's 2017 Integrated Resource Plan (April 4, 2017).
2/ Docket No. UM 1845, PacifiCorp's Application for Approval of 2017R Request for Proposals (June 1, 2017).
3/ Docket No. LC. 67, Order No. 18-138 (April 27, 2018).
4/ <u>Id</u>. at 8.

> opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the updated economic analysis by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the Energy Vision 2020 projects; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission constrained areas of Wyoming.

Q. DID YOU ASK PACIFICORP ABOUT THE JIM BRIDGER TO WALLA WALLA LINK IN DISCOVERY?

A. Yes. In response to AWEC Data Request 05, PacifiCorp confirmed that it did not model the 300MW increase in transfer capability between Jim Bridger and Walla Walla in this proceeding.[5/]

Q. WHAT IS THE IMPACT OF MODELING THIS LINK?

A. I was not able to add this new link in the GRID model because the GRID model crashed due to a server error each time I attempted to do so. I contacted PacifiCorp but was unable to resolve the error (which are not uncommon with the GRID model) prior to testimony. Based on my involvement in the EV2020 docket, I estimate the impact of this adjustment to be between $1,100,000 and $8,300,000 on a total-Company basis. Rather than applying an out of model adjustment, I recommend the link be modeled directly in the GRID model because doing so will provide a more accurate calculation of coal costs. Coal costs are calculated using an iterative process that involves several GRID model runs. Considering the link in this iterative process will impact coal output, and accordingly, will impact the $/ton price for coal included in the GRID model.

5/ AWEC/102 at 3.

b. **<u>Line Loss Benefits</u>**

Q. WHAT AMOUNT OF LINE LOSS BENEFITS DID PACIFICORP ESTIMATE WITH RESPECT TO THE EV 2020 TRANSMISSION LINE?

A. In AWEC/103, PacifiCorp estimated line loss benefits of 11.6 aMW. These line loss savings were described on page 13 of PacifiCorp's July 28, 2017 IRP Informational Filing with the Commission in Docket No. LC 67, as follows:

> [W]hen the Aeolus-to-Bridger/Anticline transmission project is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental 11.6 average MW (aMW) of energy, which equates to approximately 102 GWh, will be able to flow out of eastern Wyoming each year.

Q. DOES PACIFICORP'S FILING CONSIDER THESE LINE LOSS SAVINGS BENEFITS?

A. No. In response to AWEC Data Request 007 PacifiCorp stated that its "net power costs forecast does not include line loss savings associated with the Energy Vision 2020 (EV 2020) transmission line."[6/]

Q. WHAT DO YOU RECOMMEND?

A. I recommend applying the line loss savings PacifiCorp forecast in the 2017 IRP in the ratemaking forecast used for the TAM.

Q. WHAT IS THE IMPACT OF MODELING THIS REDUCTION?

A. I applied the line loss savings in the GRID model as a flat reduction to Wyoming Central load. Prior to the impacts of screening, and coal cost updates, the impact was $2,474,833 on a total-company basis.

6/ AWEC/102 at 5.

c. Reliability Benefits

Q. WHAT AMOUNT OF RELIABILITY BENEFITS DID PACIFICORP CONSIDER IN THE 2017 IRP?

A. To account for transmission line outages, PacifiCorp has historically de-rated the capacity of the existing 230 KV transmission line by 36.5 MW. When modeling the new transmission capacity, however, PacifiCorp removed the de-rate from the existing lines, increasing the transfer capability:

> [D]e-rates on the existing 230-kV transmission system were captured in the SO model and PaR as a 36.5 MW reduction in the transfer capability from eastern Wyoming to the Aeolus area. In simulations that include the new wind and transmission, this de-rate assumption was eliminated when the new transmission project is assumed to be placed in service at the end of October 2020.[7/]

Q. DOES PACIFICORP'S FILING INCLUDE THESE BENEFITS?

A. In response to AWEC Data Request 008, PacifiCorp argues that "reliability benefits are inherent to power costs created by GRID."[8/] I disagree. If the reliability benefits are inherent in GRID, then they would have been inherent in the System Optimizer and PaR models used in the RFP. I recommend applying these additional benefits to the transfer capabilities calculated in the GRID model.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. Since my version of the GRID model produced an error that would not allow for the addition of new transmission links or modification of existing ones, I have estimated the impact of this adjustment based on my involvement in EV 2020 to be between $2,600,000 and $4,300,000 on a total-Company basis. As discussed above, I recommend that this modeling be applied

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7/ Docket No. LC 67, PacifiCorp 2017 IRP Informational Filing at 13 (July 28, 2017).
8/ AWEC/102 at 6.

directly in the final GRID runs performed in this proceeding, so that the coal cost and plant dispatch impacts can be considered.

d. Capacity Factor

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE CAPACITY FACTORS FOR THE EV 2020 PROJECTS?

A. I recommend that the capacity factors for the EV 2020 projects that were modeled in the RFP be used as a minimum capacity factor for these facilities in the future. For this proceeding, my recommendation has no impact on NPC because PacifiCorp is using the modeled capacity factors for these resources. It may, however, have an impact in future TAM proceedings when historical data for these facilities exists. Additionally, because AWEC views this issue as related to the prudence of PacifiCorp's decision to pursue the EV 2020 projects, I will provide more discussion and justification for this proposal in my Opening Testimony in PacifiCorp's ongoing general rate case, UE 374.

III. GAS OPTIMIZATION

Q. WHAT ARE GAS OPTIMIZATION REVENUES?

A. PacifiCorp maintains pipeline rights over a broad geographic region and has many opportunities to purchase and sell gas in order to optimize the cost associated with fueling its system. These activities include purchasing at one hub and transporting to another in order to earn a margin on the price difference between the two locations. PacifiCorp's modeling of gas supply costs is based on the location of each individual plant and therefore does not consider the beneficial aspects of how PacifiCorp monetizes its gas transportation rights. In actual operations, these activities result in a reduction to power costs that offset the cost of fuel at PacifiCorp's gas plants.

Q. HAVE YOU PROPOSED AN ADJUSTMENT RELATED TO OPTIMIZATION REVENUES IN THE PAST?

A. Yes. In Docket No. UE 356, I recommend including an adjustment to account for PacifiCorp's gas optimization activities. This issue was resolved by PacifiCorp agreeing to conduct a workshop prior to this proceeding. In the workshop, PacifiCorp continued to maintain that it was not earning any incremental margins associated with its gas trading activities. After further review of the trade data for 2019, however, I continue to disagree with PacifiCorp's position.

Q. WHY DO YOU DISAGREE WITH PACIFICORP?

A. PacifiCorp's actual trade data tells a different story.

In AWEC Data Request 11, PacifiCorp was asked to provide support for the fuel supply costs for its gas plants included in Net Power Costs. PacifiCorp responded by providing the fuel cost journal entries, but the response did not detail how the fuel supply cost amounts were calculated, as requested.[9/]

In AWEC Data Request 12, PacifiCorp was requested to provide all physical purchase and sales transactions by plant. The data PacifiCorp provided, however, had all of the vital information about the transactions removed in 2018 and 2019. This was evident from the fact that versions of the spreadsheet from earlier periods had counterparty data and other fields available.[10/]

Notwithstanding, it is clear from the data in AWEC Data Requests 11 and 12 that, at times when it is economic to do so, PacifiCorp is reselling gas to earn margins, rather than burning it in its power plants.

9/ AWEC/102 at 7.
10/ Id. at 8.

Q. DOES GRID CAPTURE THESE AMOUNTS?

A. No. Since these gas optimization margins are not considered in GRID, I request that PacifiCorp provide further testimony on this issue. For purposes of this testimony, I have quantified an adjustment based on the value of actual sales transactions in 2019. In AWEC Data Request 12, I was able to identify over $20,000,000 in opportunistic gas sales revenues in 2019, although the details about these trades are somewhat unclear because much of the relevant trade data was removed from that document. Assuming an average sales price of $3.43/MMBtu and 5% margin per trade, however, this results in optimization revenues of at least $1,000,760 total-Company. Based on this estimate, I applied a downward adjustment to the TAM net power costs.

IV. MARKET PRICE FORECASTING

Q. PLEASE SUMMARIZE AWEC'S CONCERNS WITH PACIFICORP'S PRICE FORECAST.

A. As discussed in response to AWEC Data Request 01, PacifiCorp relies on broker quotes to establish its price forecast in the TAM test period. While those prices represent the cost that PacifiCorp would incur if it were to acquire a monthly block of power today for future delivery, the use of market forward prices is not necessarily indicative of what actual prices will be in the future.

Q. WHAT ANALYSIS HAVE YOU PERFORMED?

A. The below figures present an analysis exploring the accuracy of PacifiCorp's previously issued official forward price curve ("OFPCs") for both gas and electric markets. These are based on the non-confidential information that PacifiCorp provided in response to AWEC Data Request

02. The purpose of these analyses is to examine the accuracy of PacifiCorp's OFPCs issued over the historical period 2007 through 2019.

Figure 1
Mid Columbia Market Forecast Error
For PacifiCorp OFPCs issued 2007-2019

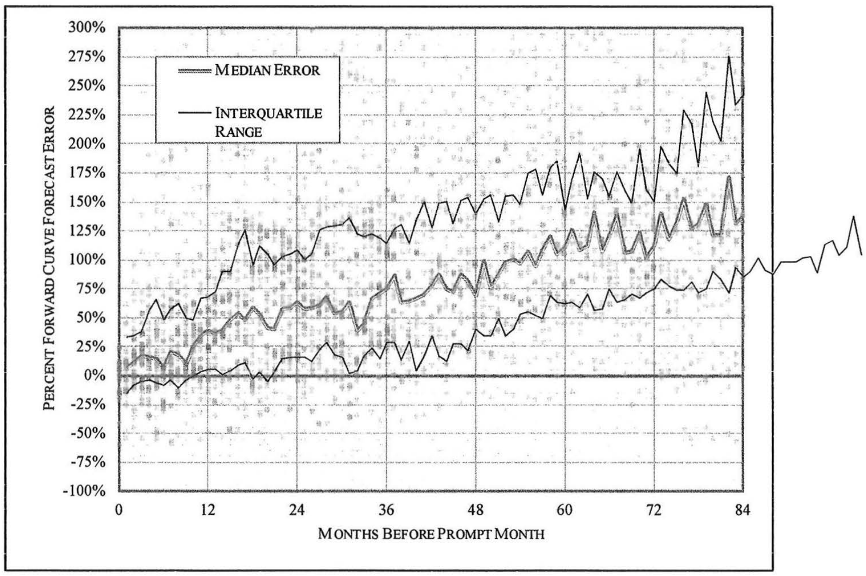


Figure 2
Palo Verde Market Forecast Error
For PacifiCorp OFPCs issued 2007-2019

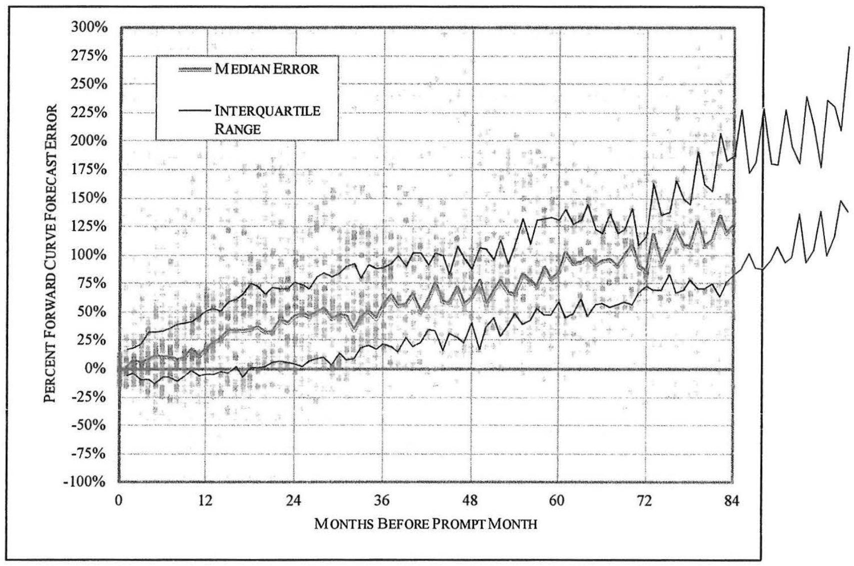
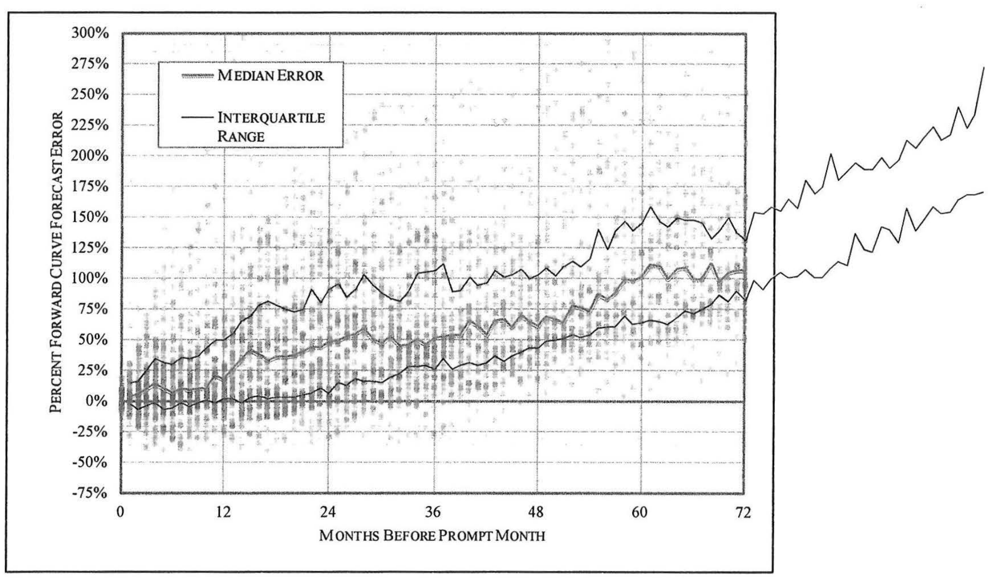


Figure 3
Henry Hub Market Forecast Error
For PacifiCorp OFPCs issued 2007-2019



Q. PLEASE PROVIDE AN OVERVIEW OF THE ABOVE FIGURES.

A. The figures are a plot of the percentage forecast error associated with forward prices included in price curves PacifiCorp issued over the period 2005 to the end of 2019. Each dot in a figure represents the percentage difference between a particular monthly price that was forecast in a forward curve and the ultimate monthly price for the given prompt month. To the extent that the error is positive, it means that the price in the forward curve exceeded the actual price. To the extent that the error is negative, it means that the price in the forward curve was less than the actual price. Along the x-axis, the set of forecast errors is separated by the number of months before the prompt month for which the forward price was calculated. Thus, a forecast error further to the right indicates the forecast error associated with a price that was forecast further in advance of the prompt month. Similarly, a forecast error on the left side of the x-axis represents a price that was forecast nearer to the prompt month. Overlaid on the figure is the median forecast error based on the number of months in advance of the prompt month that the forward prices were calculated, as well as the interquartile range of the forecast errors.

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. The above analysis shows that PacifiCorp's forward price curves tend to overestimate actual monthly prices. It also shows that the degree of overestimation increases the further ahead of the prompt month that the forecast is prepared. For an annual OFPC prepared between 2 and 13 months ahead of the prompt month (i.e., the equivalent of the November TAM forecast), for example, the average monthly forecast error was 21% at the Mid-Columbia market.

Q. BASED ON THIS ANALYSIS, WHAT DO YOU RECOMMEND?

A. I recommend a downward adjustment to day-ahead/real-time ("DA/RT") electric and gas market prices to account for the historical over-estimation. The prices in the GRID model are not representative of actual monthly prices, but rather are based on forward monthly prices. PacifiCorp calculates the day-ahead/real-time adjustment by calculating the difference between actual monthly prices and the average price for day-ahead and real-time transactions in actual operations for that month. PacifiCorp then applies the difference to the forward prices assumed in the GRID model, which are based on forward broker quotes. This is an inconsistent assumption, however, because the actual monthly market prices are not the same as the forecast monthly market prices that are input into the GRID model. As demonstrated above, the forecast monthly prices are statistically higher than the actual monthly market prices used to calculate the day-ahead/real-time adjustment. In my analysis, I have recalculated the DA/RT adjustment by making an adjustment to the forecast monthly market prices so that they can be compared on an "apples-to-apples" basis against actual monthly market prices. I also applied the adjustment to gas prices in the DA/RT model.

Q. DID YOU MAKE ANY OTHER CHANGES TO THE DA/RT ADJUSTMENTS?

A. Yes. In connection with this adjustment, I recommend normalizing the effects of the Enbridge outage in the DA/RT adjustment. The Enbridge outage was not a normal event, so it is necessary to exclude the high DA/RT adjustment amounts for the month of March 2019 from a normalized forecast. In addition to normalizing the effects of the Enbridge outage, I recommend the DA/RT be calculated over a longer period of time.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Applying the above median forecast error amounts in the DA/RT adjustment to reconcile the use of forward prices results in a $5,846,807 reduction to total-Company NPC. Applying the forecast error amount to the gas prices included in the GRID results in a $26,525,694 reduction to power costs. Collectively, these two components result in a $32,372,501 total-Company adjustment.

V. BRIDGER COAL COSTS

a. Bridger Coal Company Plant Additions

Q. WHAT PLANT ADDITIONS HAS PACIFICORP PROPOSED IN THE COST OF FUEL?

A The depreciation expense for the Bridger Coal Company ("BCC") mine includes provisional amounts for plant additions through December 31, 2021. These plant additions may be found in the confidential workpapers of PacifiCorp witness Ralston at "3.45M REV5 12-12-19/OPEX-CAPEX/14 Depr Exp 10YP.xlsx."

Q. WHAT DO YOU RECOMMEND?

A. I recommend using a rate base valuation date of December 31, 2020. Accordingly, my analysis excludes the post-rate-effective-date plant additions from the BCC depreciation expense.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing these expenses results in a $559,201 reduction to BBC's fuel budget. PacifiCorp's 2/3rds share of this amount is $372,801 on a total-Company basis.

b. Bridger Coal Company Remediation Fund

Q. PLEASE PROVIDE BACKGROUND ON THE BRIDGER COAL COMPANY RECLAMATION FUND.

A. PacifiCorp has a trust fund in place to cover reclamation costs at BCC. Contributions to the trust fund are included in the cost of fuel for the Jim Bridger Power Plant.

Q. HOW MUCH IS PACIFICORP REQUESTING OREGON RATEPAYERS CONTRIBUTE IN 2021?

A. This amount may be found in the confidential workpapers of PacifiCorp witness Ralston at "3.45M REV5 12-12-19/OPEX-CAPEX/ 01 OpsCostSchedules.xlsx", Tab "FR - Sinking Fund."

Q. WHAT DO YOU RECOMMEND?

A. Due to Oregon's exit from PacifiCorp's coal fired resources over the next several years, I recommend the Commission remove Oregon's share of the reclamation trust fund and transfer it into a regulatory liability that accrues interest at PacifiCorp's cost of capital. Contributions would be tracked in general rates and removed from net power costs. If the reclamation contribution amounts are continued to be included in fuel costs, it will be difficult to track the funds in order to provide assurance that customers receive credit for all contributions made towards the reclamation liability.

Q. WHAT INTEREST RATE DO YOU RECOMMEND?

A. I recommend that the liability account accrue interest at PacifiCorp's cost of capital.

Q. HAVE YOU IDENTIFIED ANY INCONSISTENCIES IN THE TRUST FUND CONTRIBUTION AMOUNTS?

A. Yes. I have identified what appear to be inconsistencies between the amounts that PacifiCorp has included in rates and the amounts that it has actually contributed. For example, the contribution amount for 2019 show in Tab "FR - Sinking Fund" cell "E15" of the workpaper "3.45M REV5 12-12-19/OPEX-CAPEX/ 01 OpsCostSchedules.xlsx" is materially less than the amount that was considered in the 2019 TAM.

Q. HOW DO YOU RECOMMEND THESE INCONSISTENCIES BE RESOLVED?

A. Given the substantial costs involved, I recommend the Commission open an investigation to audit the trust fund and require PacifiCorp to reconcile the amount of trust fund contributions historically included in rates and the amounts actually contributed to the trust.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Based on PacifiCorp's 2/3rds share of the mine, moving the reclamation liability contributions to a regulatory asset will reduce net power costs by $16,330,920 on a total-Company basis.

VI. DIRECT ACCESS OPT-OUT PROGRAM

Q. WHAT CHANGES DO YOU RECOMMEND FOR PACIFICORP'S OPT-OUT PROGRAM?

A. In the interest of reducing the need to acquire replacement capacity when PacifiCorp's coal fired resources are retired from Oregon rates, I recommend the Direct Access opt-out program be restructured to provide potential participants with more efficient price signals for participating in the program. The current opt-out charge for PacifiCorp requires a customer to pay stranded costs for 10 years of fixed cost recovery over a 5-year period. Notwithstanding its need for new resources, PacifiCorp's opt-out program has the longest stranded cost recovery period in Oregon. The stranded cost period for PGE's opt-out program, for example, is just five years. The punitive nature of the opt-out charge for PacifiCorp is compounded by the fact that customers are required to finance the 10 years of stranded costs over a 5-year period. As a result, PacifiCorp's program is infeasible from the economic perspective of customers. Thus, even if the system would benefit from departing load, through the avoidance of building new capacity, it is probable that customers will not participate.

Q. WILL SHORTENING THE TRANSITION PERIOD SEND A BETTER PRICE SIGNAL TO PARTICIPATING CUSTOMERS?

A. Yes. Since PacifiCorp will be imminently retiring coal-fired resources, or at least removing those resources from rates, shortening the transition period used in the opt-out program will help Oregon avoid acquiring new resources.

Q. WHY WAS THE 10-YEAR TRANSITION PERIOD ORIGINALLY ADOPTED?

A. The 10-year period was justified based on Section X of the 2010 protocol, which required the direct access loads of Oregon to be included in the dynamic allocation factors.

Q. DO THE PROVISIONS OF THE 2010 PROTOCOL USED TO JUSTIFY THE 10-YEAR PERIOD STILL APPLY?

A. No. Section X of the 2010 protocol was rewritten in its entirety in the 2017 Protocol. Under the new provisions, Oregon is free to adopt any stranded cost period which the Commission finds to be reasonable. Accordingly, it is no longer necessary under the terms of the Multi-State Process ("MSP") agreement to use a 10-year period for Oregon's opt-out program. The 2020 Protocol retained the language of the 2017 Protocol.

A. HOW DO YOU RECOMMEND THE STRANDED COST PERIOD BE DETERMINED?

A. Rather than specifying the number of years that a participating customer must pay a transition adjustment, I recommend the program be designed around the specific exit dates for coal-fired resources. Instead of specifying the term of the transition period, I propose redesigning the program such that it specifies the quantity of load ("aMW") eligible to participate in the program by retirement date. Participating customers will be required to pay transition charges until the specified coal retirement date. If more customers apply to participate in the program than specified, then the customer further down in the queue will be required to pay transition adjustments for a longer period of time, until the next resource is retired.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Table 2 provides an example of the direct access eligibility based on the retirement dates in the 2020 Protocol. These dates and the associated capacity amounts would be subject to change as the respective retirement dates change:

Table 2
Example of Opt-Out Eligibility Queue

Year	Coal Plant Retirements	Capacity	Oregon SG%	Oregon Capacity	Opt-out Eligible
2023	Cholla 4/ JB1	741	26.46%	196	98
2025	JB 3-4/ Naughton 3-4/ Craig 1	1,500	26.46%	397	198
2026	Craig 2	82	26.46%	22	11
2027	Colstrip 3-4/ DJ 1-4	903	26.46%	239	119
2029	Hunter/ Huntington/ Wyodak	2,335	26.46%	618	309

Under the above example, I have set the eligible capacity at 50% of the amount of Oregon capacity that is expected to retire by year. Under this approach, the first 98 aMW to participate in the program would be responsible for transition adjustment until December 31, 2023. The next 198 aMW to participate in the program would have to pay a transition charge until 2025, and so on. Under this approach, if there is high demand for the program, customers will have to pay transition adjustments for longer periods of time. This will have the effect of sending better price signals to customers, who might be willing to pay transition adjustments for a longer period of time in order to secure a high queue position.

VII. TAM GUIDELINES

Q. DO YOU INTEND TO PROPOSE CHANGES TO THE TAM GUIDELINES AND ADDRESS PACIFICORP'S PROPOSED CHANGES TO THE TAM AND TAM GUIDELINES?

A. Yes; however, my understanding of the TAM Guidelines and the stipulations and orders that adopted those guidelines is that any recommended changes to the TAM Guidelines should be proposed in a concurrently filed general rate case.[11/] This also appears to be PacifiCorp's understanding, as it has proposed substantial changes to the TAM and the TAM Guidelines in its testimony in UE 374, its 2020 general rate case.[12/] I disagree with many of PacifiCorp's proposed changes and also believe the existing TAM Guidelines can be improved, but will address these issues in my Opening Testimony in UE 374.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

11/ Docket No. UE 207, Order No. 09-432, App. A at 5:9-16 (Oct. 30, 2009) ("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…in future rate general rate cases.).

12/ Docket No. UE 374, Exh. PAC/500-501.

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

PACIFICORP

PAC/1609

Docket No. UE 216 Order No. 10-363

August 23, 2021

ORDER NO 10-363
Entered 09/16/2010

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 216

In the Matter of PACIFICORP, dba PACIFIC POWER, 2011 Transition Adjustment Mechanism	ORDER

DISPOSITION: STIPULATION ADOPTED

I. INTRODUCTION

On February 26, 2010, PacifiCorp, dba Pacific Power (Pacific Power or the Company) filed revised tariff sheets for its 2011 Transition Adjustment Mechanism (TAM), to be effective January 1, 2011. The purpose of the TAM filing is to update net power costs (NPC) to set transition adjustments for the Company's Oregon customers who may choose direct access service in the November 2010 open enrollment window.

In its initial filing Pacific Power forecasted total normalized system-wide NPC for the test period (12 months ending December 31, 2011) of about $1.28 billion. On an Oregon-allocated basis, the forecast normalized NPC in the initial filing were about $312.8 million. That amount is about $56.6 million higher than the $256.1 million included in rates through the NPC baseline established in the Company's 2010 TAM proceeding (docket UE 207), or $69.2 million higher, as adjusted for load loss in 2011. That amount would have resulted in an overall increase in Oregon rates of about 7 percent.

The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right. The Industrial Customers of Northwest Utilities (ICNU) and Sempra Energy Solutions, LLC (Sempra) filed petitions to intervene that were granted without objection.

On April 21, 2010, Pacific Power filed a summary of corrections or omissions from its initial filing, to be incorporated in the Company's Rebuttal Update scheduled for July 2, 2010. On May 12, 2010, the Staff of the Public Utility Commission of Oregon (Staff), CUB, ICNU, and Sempra filed reply testimony.

On July 7, 2010, Pacific Power filed its Net Power Cost Rebuttal Update. As explained in its exhibits, the net effect of the Company's filing was to increase net power costs by about $10.9 million on a total company basis.

Also on July 7, 2010, Pacific Power filed a joint stipulation of all parties intended to resolve all issues in the proceeding. The stipulation is attached as Appendix A. In the stipulation, the parties agree that the total-Company NPC for 2011 will be $1.233 billion, subject to final power cost updates. The parties agree that this is an Oregon-allocated NPC of $301.8 million, or an increase of $58.2 million (5.9 percent, including the load change adjustment.) The amount of NPC in the stipulation is a reduction of $11 million from the amount incorporated in Pacific Power's initial filing.

II. PACIFIC POWER'S APPLICATION

As explained by Pacific Power, NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. NPC are calculated for a future test period based on projected data, using the Generation and Regulation Initiative Decision model (GRID). GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

As noted above, in its initial filing Pacific Power forecasted an NPC increase of $56.6 million compared to the 2010 NPC in rates. The Company's proposed adjustment reflects the new tariff (Schedule 201) adopted in its 2009 general rate case (docket UE 210). This new tariff reflects *a decrease in* Oregon loads, when compared to the 2010 projected loads from docket UE 206. To capture this reduction in Oregon loads, rates were designed to collect an additional $12.5 million. The combination of the $56.6 million in increased NPC and the $12.5 million of decreased revenues results in the total proposed revenue increase of $69.2 million (about 7 percent).

As stated by Pacific Power, the NPC increase is driven by a range of factors, including changes in the Company's portfolio of wholesale purchase and sales contracts, expiration of the long-term gas supply contracts for the Hermiston gas-fired generating plant, increases in third-party coal contract costs (mitigated by decreases in captive coal costs) and inclusion of the cost of integrating increasing amounts of wind resources into the Company's integrated six-state system. Offsetting factors that drive NPC downward in 2011 include decreases in the load forecast and the addition of new transmission and generation resources. Each of these factors is discussed in the testimony filed by Pacific Power in support of its application.

Consistent with the TAM guidelines adopted in Order No. 09-274 (docket UE 199), Pacific Power proposes to allocate the NPC to customer classes based on the generation allocation factors from the Company's most recent cost of service study, which was filed in the Company's current general rate case with the TAM filing. According to Pacific Power, this methodology accurately allocated NPC to each customer class and ensures synchronization between the TAM and general rate case.

According to Pacific Power, its application was prepared consistent with the TAM guidelines adopted by the Commission in Order No. 09-274. The filing includes updates to all NPC components. The Company provided interested parties with its workpapers and access to the Company's GRID model

III. PACIFIC POWER'S NPC REBUTTAL UPDATE

As noted above, on July 7, 2010, Pacific Power filed its Rebuttal Update. In support of its filing, the Company offered three exhibits: Exhibit 1 – Summary of Updates; Exhibit 2 – Explanation of Updates; and Exhibit 3 – Update of Attachment A to Stipulation for Oregon Allocation.

The total impact of all of the adjustments increases net power costs by about $10.9 million on a total Company basis. The material factors contributing to the higher costs include an update to the Official Forward Price Curve, an increase to the Idaho Power transmission rate, and updated coal costs.

IV. THE STIPULATION

As noted above, on July 7, 2010, Pacific Power filed a stipulation among all parties. The parties agreed that the total-Company NPC for 2011 would be $1.233 billion, subject to the Rebuttal and Final Updates. They further agreed that this results in an Oregon-allocated NPC of $301.8 million, an increase of $58.2 million (including the load change adjustment).

The parties agreed that the $11 million reduction reflects consideration of the issues in the testimony of Staff, CUB, ICNU, and Sempra, changes in net power costs for corrections identified in the Company's April 21, 2010 filing, and corrections for the addition of a reserve requirement to the Dunlap wind project, the addition of Tieton Hydro to non-owned generation reserve requirements, and a correction to Lower Valley Energy Upper Facility qualifying facility pricing. These adjustments resolve all issues related to NPC as of the date of the Company's July 7, 2010, update.

The parties agree that the stipulated $11 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the parties have accepted any elements of the Company's NPC study. However, Pacific Power does agree to reflect certain specified changes to its methodology in the Company's 2012 TAM filing.

The stipulation includes a number of other provisions that address concerns raised by the parties. In future stand-alone TAM filings Pacific Power agrees to reflect forecast changes in Other Revenues for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in UE 217. The Company agrees to file to modify its Open Access Transmission Tariff to include charges for wind integration services to non-owned wind facilities and update line loss charges in its next rate case before the Federal Energy Regulatory Commission. Pacific Power agrees to reflect the final

Commission decision in docket UM 1355 in its 2011 TAM filing, if the decision is timely. ICNU agreed to dismiss and not refile its deferred accounting application in UM 1465. Pacific Power agrees to file an attestation with its Indicative Filing in this and in future TAM proceedings that will confirm that all contracts executed prior to the contract lockdown date have been included (or will identify any exceptions and the reasons why such contracts were excluded). The parties will work to develop a proposal to consider a change to the Company's TAM schedule, from a January 1 effective date to a July 1 effective date. Pacific Power agrees to increase the Schedule 294 transition adjustment to reflect the potential value associated with reselling BPA Point to Point wheeling rights. Pacific Power will continue to respond to bill inquiries from potential direct access customers, providing such information as is practicable.

The stipulation provides that Pacific Power will revise its rates to reflect the rate design agreed to by the parties in docket UE 217 (the general rate case).

The stipulation provides that Pacific Power will file its Final Update on November 15, 2010. The parties agree to make a good faith effort to follow specified procedures for challenges to the Final Update and compliance filing.

V. JOINT TESTIMONY

On July 26, 2010, Pacific Power filed the joint testimony of the parties in support of the stipulation. As stated in the testimony, the stipulation is a comprehensive settlement of all issues in the TAM proceeding. The stipulating parties further note in their testimony that the stipulation includes a number of other provisions, as summarized above.

The parties state their agreement to reduce Pacific Power's Oregon-allocated NPC by $11 million, resulting in an increase of $58.2 million to Oregon-allocated NPC (including the load change adjustment). They note that the Update filings may increase or decrease the final amount to be recovered in rates.

According to the parties, the stipulated rate spread is consistent with the TAM Guidelines and the stipulation adopted by the Commission in docket UE 199. The proposed Schedule 201 revenues by rate schedule were determined by spreading the total forecast NPC for the test year to the rate schedules in the same manner as the revenues for Schedule 200 were spread to the rate schedules in the Company's current general rate case.

The parties explain in the stipulation the procedures regarding challenges to Pacific Power's Final Update and compliance filings. They note that parties retain their procedural rights to raise any issue regarding the Final Updates prior to and during the Commission's public meeting. Parties may request that a specific amount of the tariff change be subject to deferral, subject to specified procedures.

The parties note that the stipulation provides for methodological changes in the 2012 TAM, and explain these changes. They explain other provisions of the stipulation, including accounting for changes in Other Revenue, the FERC filing to modify the

Company's Open Access Transmission Tariff to include charges for wind-integration services to non-owned wind facilities, the incorporation of the outcome of docket UM 1355, the resolution of ICNU's application for deferred accounting (docket UM 1465), the adjustments to reflect the potential value associated with reselling BPA wheeling rights, and billing issues related to direct access customers.

The parties agree to work together to develop a proposal for a change in Pacific Power's TAM schedule that would effectuate a change in the effective date from January 1 to July 1 of each year.

The parties agree that their proposed rates would be just and reasonable. Because the July Update had not been reviewed, the Final Updates have not been filed, and the final TAM rates are unknown, the parties have not yet reached agreement that the final TAM rates will be fair, just and reasonable.

VI. DISCUSSION

In this case the parties have submitted a stipulation that encompasses a broad range of procedural and substantive issues. The scope of their stipulation reflects the scope of the testimony that was filed by the parties. The scope of their testimony reflects the extent of their discovery and preparation. Their extensive participation provides the Commission with a high degree of comfort that the stipulation is in the public interest and should be approved.

The proposed adjustment to NPC appears reasonable, based on the issues raised by the parties to this proceeding. The resolution of issues not related directly to the calculation of the 2011 NPC affirms the parties' effort and good faith. The Commission commends the parties for their effort to improve the TAM approval process.

The stipulation is adopted.

VII. ORDER

IT IS ORDERED that:

1. Advice No. 10-002, filed by PacifiCorp, dba Pacific Power, on February 26, 2010, is permanently suspended.

2. The Stipulation, by and among PacifiCorp, dba Pacific Power, the Public Utility of Oregon Commission Staff, the Industrial Customers of Northwest Utilities, Sempra Energy LLC, and the Citizens' Utility Board of Oregon, is approved and is attached as Appendix A.

3. PacifiCorp, dba Pacific Power shall update its net power costs (NPC) to reflect the provisions of the stipulation to establish its Transition Adjustment Mechanism (TAM) NPC for the calendar year 2011, with tariffs to be effective January 1, 2011.

Made, entered, and effective SEP 16 2010.

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner

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 216

In the Matter of: PACIFICORP, dba PACIFIC POWER 2011 Transition Adjustment Mechanism Schedule 201, Cost-Based Supply Service	**STIPULATION**

This Stipulation is entered into for the purpose of resolving the issues among the parties to UE 216, PacifiCorp's (or the "Company") proposed transition adjustment mechanism ("TAM").

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("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 February 26, 2010, PacifiCorp filed revised tariff sheets for Schedule 201, Net Power Costs, Cost-Based Supply Service, to be effective January 1, 2011, which implements PacifiCorp's 2011 TAM. The purpose of the TAM filing is to update net power costs ("NPC") for 2011 and to set transition adjustments for Oregon customers who choose direct access in the November 2010 open enrollment window.

3. The February 26, 2010 TAM filing ("Initial Filing") reflected total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2011) of approximately $1.28 billion. On an Oregon-allocated basis, the forecasted normalized NPC in the Initial Filing were approximately $312.8 million. This amount is approximately $56.6 million higher than the $256.1 million included in rates through the NPC baseline established

in the 2010 TAM (Docket UE 207), or $69.2 million as adjusted for forecasted load loss in 2011. This would have resulted in an overall increase to Oregon rates of approximately 7.0 percent.

4. All Parties participated in three settlement conferences on June 10, 2010, June 14, 2010 and June 24, 2010.

5. The Parties have reached a comprehensive settlement of all issues raised prior to the Rebuttal Update in this case. The settlement establishes the baseline 2011 TAM NPC in rates, subject to TAM updates, and various TAM-related policy issues.

AGREEMENT

6. <u>2011 NPC</u>. The Parties agree that the total-Company NPC for 2011 will be $1.233 billion, subject to the Rebuttal and Final Updates described in Section 7. The Parties agree that this is an Oregon-allocated NPC of $301.8 million or an increase of $58.2 million, including the load change adjustment, as shown in Exhibit A. This is based on the Parties agreement that Oregon-allocated NPC shall be reduced by $11.0 million. The $11.0 million reduction reflects consideration of the issues in the testimony of Staff, ICNU, CUB and Sempra; changes in net power costs for corrections identified in the Company's April 21, 2010 filing; and corrections for the addition of a reserve requirement to the Dunlap wind project, the addition of Tieton Hydro to non-owned generation reserve requirements, and a correction to Lower Valley Energy Upper Facility qualifying facility pricing. These adjustments resolve all issues related to Net Power Costs as of the date of the Company's July 7, 2010 update, and as reflected in paragraph 7, the correction of errors resulting from future updates are the only error corrections that may be made after execution of this Stipulation. The Parties, including PacifiCorp, cannot make additional error corrections or other changes to the Company's previous filings.

7. <u>NPC Baseline and Rebuttal and Final Updates</u>. The Company will update its Initial Filing consistent with the schedule adopted in this proceeding and as specified in the

TAM Guidelines, adopted in Order No. 09-274 and modified in Order No. 09-432. The Company shall file its Rebuttal Update on July 7, 2010, its Indicative Filing on November 8, 2010 and the Final Update on November 15, 2010 (collectively the Indicative Filing and the Final Update are referred to as the Final Updates). Parties agree that errors resulting from future updates are the only error corrections that may be made after execution of this Stipulation. Staff and Intervenors reserve the right to challenge all other elements of the Updates. The Updates may increase or decrease the Oregon-allocated increase of $58.2 million from base NPC.

8. Adjustments to NPC. The Parties agree that the stipulated $11 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the Parties have accepted any elements of the Company's NPC study. The Company does, however, agree to reflect the methodology changes listed in this paragraph in the 2012 TAM. The Company will also make the methodology changes listed in this paragraph in subsequent TAM filings, absent a change in facts or circumstances identified by the Company. The Company agrees to provide Parties with the details of these modeling changes by mid-January 2011 and to meet with Parties, if requested. The obligations in Paragraph 8 apply to the Company. Staff and Intervenors reserve the right to review, challenge and propose alternatives to the methodological changes listed below.

a. Screens – The Company will use a daily screening methodology that is more effective than that used in UE 216 and is based on logic which commits all gas plants up and backs down those that are not economic.

b. Black Hills CTs – The Company will use a four-year average for the costs of the Black Hills combustion turbines.

c. Heat Rates – The Company will not implement adjustments for scrubbers or other capital projects, but instead will rely on the traditional analysis of four years of actual data to derive the heat rate inputs.

d. APS Supplemental Coal and Other – The Company will model the option contracts to be exercised only when economic.

e. The Company will not include inter-hour wind integration charges for non-owned wind facilities.

f. The Company will include modeling of non-firm transmission links and costs using a four-year average.

9. Other Revenue in Future Stand-Alone TAM Filings. In future stand-alone TAM filings, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 217. Exhibit B contains the revenue baselines from Docket UE 217 for the storage and exchange agreements for Seattle City Light Stateline and the non-Company owned Foote Creek projects, revenues from the Bonneville Power Administration associated with the South Idaho Exchange, steam revenues for Little Mountain and royalty offset revenues for the Georgia Pacific Camas contract.

10. Wind Integration Charges for Non-Owned Wind Facilities/Line Losses. The Company agrees to file to modify its Open Access Transmission Tariff to include charges for wind integration services to non-owned wind facilities and update line loss charges in its next rate case before the Federal Energy Regulatory Commission, which is scheduled to be filed in June 2011.

11. UM 1355 – Forced Outage Rates. The Company agrees to reflect the final Commission decision in Docket UM 1355 in the 2011 TAM if the decision is timely and issued prior to the Indicative Filing. The Parties agree that the adopted schedule in UM 1355, including the proposed Commission decision date, would result in a timely final order.

PacifiCorp will implement the final Commission decision in UM 1355, even if a party in UM 1355 seeks rehearing, reconsideration or appeal of the Commission decision. The Parties agree that this provision does not contain an express or implied waiver of PacifiCorp's rights, including but not limited to the right to seek clarification or challenge the UM 1355 decision or to seek to have the impact of the decision made subject to refund or deferral.

12. UM 1465 – 2010 TAM ICNU Deferral. ICNU agrees to dismiss and not refile its deferred accounting application in Docket UM 1465 based upon the resolution of the Company's application in Docket UP 260, authorizing the Company to sell Oregon-allocated renewable energy credits generated in 2010 that are ineligible for Oregon's renewable portfolio standard, with net proceeds to be credited to the property sales balancing account.

13. Attestation with Indicative Filing. The Company agrees to file an attestation with the Indicative Filing in this case and in future TAM filings. The attestation will confirm that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing and will identify any exceptions and the reason why such contracts were excluded.

14. Challenges to Final Updates. Without waiving any procedural rights, the Parties agree to make a good faith effort to follow the following procedures for challenges to the Final Updates and compliance filing. Staff and Intervenors retain their procedural rights to raise any issue regarding the Company's Final Updates to the Commission prior to and during the Commission public meeting, including filing for a deferral of costs related to the final TAM updates or requesting that a portion of the TAM be allowed subject to refund. These procedures will apply to the 2011 and 2012 TAM filings. During the 2013 TAM filing, the Parties will review the effectiveness of these procedures.

a. PacifiCorp agrees to make a good faith effort to respond to all discovery requests after the Indicative Filing in five business days.

b. At least 10 business days before the Commission public meeting scheduled immediately prior to the effective date of the compliance filing, a Party will provide notice to the Parties of any potential concerns with the Company's Final Updates. The notice will identify the specific elements of the Updates that are relevant to the potential challenge and provide an explanation of the Party's concern.

c. No more than five business days after receiving the Party's notice, the Company will provide an initial response to the Parties regarding the concerns raised in the notice and the Parties will work to reach resolution of the issue.

d. If the matter is not resolved by the Parties prior the Commission public meeting, the Parties may make recommendations to the Commission at the public meeting to set a process to resolve the matter, if additional process is required. The recommendations may include that a specific amount of the tariff change will be subject to deferral until the Commission resolves the matter through additional process.

e. PacifiCorp will not oppose the filing of a deferral of any limited and specific cost which is identified by the Parties at least 10 business days before the Commission public meeting. Specifically, the Company will not challenge the deferral on the basis that it fails to meet the Commission's standards for deferred accounting as initially set forth in Order No. 05-1070 (Docket UM 1147), including issues related to the materiality of the filing and a showing of substantial harm. PacifiCorp otherwise retains the right to object to subject to refund or deferral treatment.

f. The Parties agree to request a schedule that will result in a Commission decision within 90 days of the effective date for new rates for any additional process after the Commission public meeting.

g. If the final Commission decision on any challenges to the Final Updates results in changes to the transition adjustments approved in Schedules 294 and 295, the Company may reflect in the direct access balancing account any difference between the approved transition adjustments and the transition adjustments that would have been in effect consistent with the Commission's decision on the challenged items.

15. Schedule for Future PacifiCorp TAMs. The Parties will work collaboratively to develop a proposal by fall of 2010 to consider a change to PacifiCorp's TAM schedule from an annual filing with a rate effective date of January 1 to an annual filing with a rate effective date of July 1. The proposal will consider mechanisms to mitigate financial impacts to PacifiCorp due to a potential six-month delay during the transition period. The Parties agree to work in good faith to reach agreement in a timeframe that will avoid a March 1, 2011 TAM and general rate case filing date.

16. BPA Transmission Credit for Direct Access. PacifiCorp agrees to increase the Schedule 294 transition adjustment by $(0.50)/MWh for the 2011 TAM for Schedule 747 and 748 customers to reflect the potential value associated with reselling BPA Point to Point ("PTP") wheeling rights from Mid-C to the Company's Oregon Service territory that are freed-up as a result of customers choosing direct access.

PacifiCorp also agrees to meet with an Energy Service Supplier ("ESS") upon request in advance of the November 2010 shopping window to discuss price, terms and potential quantities of BPA PTP wheeling rights to be purchased from PacifiCorp for delivery from all points of receipt considered to be Mid-C to the Company's Oregon service territory to serve direct access load.

Nothing in this agreement obligates PacifiCorp to sell any transmission rights to an ESS. PacifiCorp further agrees to evaluate this issue using the actual direct access customer data that results from the November 2010 shopping window, report its findings back to the parties, and use any knowledge gained to guide its filing of the 2012 TAM.

17. Direct Access Billing Information. PacifiCorp will continue to respond as appropriate to individual bill inquiries by potential direct access customers. To the extent that additional information is requested by a participating direct access customer on an on-going basis, the Company will endeavor to provide such information as practicable, consistent with

Schedule 300, Rule 11-2. Nothing in this provision prejudges the appropriateness of application of Schedule 300, Rule 11-2 in these circumstances.

Prior to the November 2010 shopping window, PacifiCorp will work with interested Parties to identify the billing information that PacifiCorp's CSS billing system can provide on a routine basis to direct access customers sufficient to allow such customers to reconcile their bills to the PacifiCorp tariff. If resolution of this issue is not reached by the start of the 2011 shopping window, the Parties agree to support the establishment of a collaborative process to address this issue.

18. Schedule 201. The Company will revise the Schedule 4 rates in Schedule 201 to reflect the rate design agreed to by the parties in Docket UE 217, the Company's general rate case proceeding. The rate spread will be as shown in Exhibit C.

19. Tariff. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 201 rates and revised transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 216, to be effective January 1, 2011, reflecting rates as agreed in this Stipulation.

20. This Stipulation will be offered into the record as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at hearing, and recommend that the Commission issue an order adopting the Stipulation.

21. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

22. 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 shall have the rights provided in OAR 860-014-0085, including the right to withdraw from the Stipulation, and shall be entitled to seek reconsideration or appeal of the Commission's Order.

23. 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.

24. 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: 6 July 2010

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: 7/6/10

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: [signature]

Date: 7-6-2010

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

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PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: Irion Sanger

Date: July 6, 2010

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: Greg Cede

Date: July 6, 2010

Exhibit A

CY 2011 TAM

	ACCOUNT	UE-207 FINAL CY 2010	TAM CY 2011		Factors CY 2010	2011 GRC Factors CY 2011	UE-207 FINAL CY 2010	TAM CY 2011
Sales for Resale								
Existing Firm PPL	447	24,974,154	25,032,103	SG	26.877%	26.177%	6,712,274	6,552,676
Existing Firm UPL	447	25,490,589	25,490,589	SG	26.877%	26.177%	6,851,076	6,672,694
Post-Merger Firm	447	641,195,998	594,135,708	SG	26.877%	26.177%	172,333,505	155,527,424
Non-Firm	447	55,979,012	-	SE	25.002%	24.283%	13,995,816	-
Total Sales for Resale		747,639,753	644,658,400				199,892,672	168,752,793
Purchased Power								
Existing Firm Demand PPL	555	58,677,959	47,758,104	SG	26.877%	26.177%	15,770,807	12,501,681
Existing Firm Demand UPL	555	46,338,071	48,168,584	SG	26.877%	26.177%	12,454,230	12,609,132
Existing Firm Energy	555	57,763,587	52,340,132	SE	25.002%	24.283%	14,441,994	12,709,916
Post-merger Firm	555	376,161,158	490,088,073	SG	26.877%	26.177%	101,100,399	128,290,783
Secondary Purchases	555	(12,954,749)	-	SE	25.002%	24.283%	(3,238,933)	-
Seasonal Contracts	555		-	SSGC	0.000%	0.000%	-	-
Other Generation Expense	555	7,682,475	38,855,180	SG	26.877%	26.177%	2,064,810	10,171,154
Total Purchased Power		533,668,503	677,210,072				142,593,306	176,282,667
Wheeling Expense								
Existing Firm PPL	565	43,189,893	40,049,244	SG	26.877%	26.177%	11,608,098	10,483,726
Existing Firm UPL	565	168,268	259,960	SG	26.877%	26.177%	45,225	68,050
Post-merger Firm	565	100,936,303	99,966,153	SG	26.877%	26.177%	27,128,533	26,168,227
Non-Firm	565	253,429	101,247	SE	25.002%	24.283%	63,362	24,586
Total Wheeling Expense		144,547,893	140,376,605				38,845,218	36,744,589
Fuel Expense								
Fuel Consumed - Coal	501	610,479,015	638,135,027	SE	25.002%	24.283%	152,631,345	154,960,306
Cholla / APS Exchange	501	55,113,078	56,675,765	SSECH	25.408%	24.812%	14,003,311	14,062,190
Fuel Consumed - Gas	501	7,304,914	6,171,919	SE	25.002%	24.283%	1,826,367	1,498,746
Natural Gas Consumed	547	410,130,960	390,763,656	SE	25.002%	24.283%	102,540,527	94,890,350
Simple Cycle Combustion Turbines	547	11,664,948	9,951,264	SSECT	23.286%	22.403%	2,716,330	2,229,400
Steam from Other Sources	503	3,498,000	3,565,701	SE	25.002%	24.283%	874,566	863,442
Total Fuel Expense		1,098,190,915	1,105,253,332				274,592,445	268,504,434
Net Power Cost		1,028,767,558	1,278,181,609				256,138,297	312,778,897

Settlement Adjustment	(11,000,000)
OR-Allocated NPC Baseline in Rates	301,778,897
Increase Absent Load Change	45,640,600
Weighted Ave OR Allocation Factor	0.24471
Updated NPC Baseline in Rates	1,233,229,734

Oregon-allocated NPC Baseline in Rates from UE 207	256,138,297
$ Change due to load variance from UE-207 forecast	(12,529,976)
2011 Recovery of NPC in Rates	243,608,321

Increase Including Load Change	58,170,576

Exhibit B

PacifiCorp
Other Revenues - Baseline

	12 ME Dec 2011	OR Factor	OR %	OR Alloc	Reference
Seattle City Light - Stateline Wind Farm	4,923,706	SG	26.177%	1,288,883	Attachment OPUC 21 (UE-216)
Non-company owned Foote Creek	2,277,984	SG	26.177%	596,310	Attachment OPUC 21 (UE-216)
BPA South Idaho Exchange	8,553,309	SG	26.177%	2,239,007	Attachment OPUC 21 (UE-216)
Little Mountain Steam Revenues	6,873,305	SG	26.177%	1,799,231	UE 217 Exhibit PPL/1102, Page 5.2
James River Royalty Offset	5,430,652	SG	26.177%	1,421,586	UE 217 Exhibit PPL/1102, Page 5.2
Total Other Revenue	28,058,956			7,345,017	

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Exhibit C

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (6) + (7)	(9)	(10)	(11) (9) + (10)	(12) (9) - (6)	(13) (12)/(6)	(14) (11) - (8)	(15) (14)/(8)	
	Residential															
1	Residential	4	4	484,011	5,306,840	$472,654	$19,369	$492,023	$497,805	$19,369	$517,174	$25,151	5.3%	$25,151	5.1%	1
2	Total Residential			484,011	5,306,840	$472,654	$19,369	$492,023	$497,805	$19,369	$517,174	$25,151	5.3%	$25,151	5.1%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,207	1,013,838	$94,181	($628)	$93,553	$99,099	($628)	$98,471	$4,918	5.2%	$4,918	5.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,419	2,011,827	$133,835	$10,844	$144,679	$142,877	$10,844	$153,721	$9,042	6.8%	$9,042	6.3%	4
5	Gen. Svc. 201 - 999 kW	30	30	882	1,386,076	$85,559	$4,215	$89,774	$91,653	$4,215	$95,868	$6,094	7.1%	$6,094	6.8%	5
6	Large General Service >= 1,000 kW	48	48	212	2,349,055	$128,583	($2,726)	$125,857	$138,860	($2,726)	$136,134	$10,277	8.1%	$10,277	8.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	381,991	$19,268	($446)	$18,822	$20,887	($446)	$20,441	$1,619	8.1%	$1,619	8.2%	7
8	Agricultural Pumping Service	41	41	6,211	149,120	$16,054	($3,276)	$12,778	$16,604	($3,276)	$13,328	$550	3.4%	$550	4.3%	8
9	Agricultural Pumping - Other	33	33	2,056	127,459	$5,327	$272	$5,599	$5,327	$272	$5,599	$0	0.0%	$0	0.0%	9
10	Total Commercial & Industrial			93,994	7,419,366	$482,807	$8,255	$491,062	$515,307	$8,255	$523,562	$32,500	6.7%	$32,500	6.6%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,167	10,138	$1,332	$136	$1,468	$1,457	$136	$1,593	$125	9.4%	$125	8.5%	11
12	Street Lighting Service	50	50	258	10,594	$1,198	$144	$1,342	$1,305	$144	$1,449	$107	8.9%	$107	8.0%	12
13	Street Lighting Service HPS	51	51	710	16,563	$3,021	$338	$3,359	$3,286	$338	$3,624	$265	8.8%	$265	7.9%	13
14	Street Lighting Service	52	52	65	1,061	$117	$15	$132	$130	$15	$145	$13	11.1%	$13	9.9%	14
15	Street Lighting Service	53	53	266	9,250	$605	$83	$688	$653	$83	$736	$48	7.9%	$48	7.0%	15
16	Recreational Field Lighting	54	54	103	847	$75	$7	$82	$83	$7	$90	$8	10.7%	$8	9.8%	16
17	Total Public Street Lighting			8,569	48,453	$6,348	$723	$7,071	$6,914	$723	$7,637	$566	8.9%	$566	8.0%	17
18	Total Sales to Ultimate Consumers			586,574	12,774,659	$961,809	$28,347	$990,156	$1,020,026	$28,347	$1,048,373	$58,217	6.1%	$58,217	5.9%	18
19	Employee Discount				18,045	($397)	($17)	($414)	($418)	($17)	($435)	($21)		($21)		19
20	Total Sales with Employee Discount			586,574	12,774,659	$961,412	$28,330	$989,742	$1,019,608	$28,330	$1,047,938	$58,196	6.1%	$58,196	5.9%	20
21	AGA Revenue					$2,800		$2,800	$2,800		$2,800	$0		$0		21
22	Total Sales with Employee Discount and AGA			586,574	12,774,659	$964,212	$28,330	$992,542	$1,022,408	$28,330	$1,050,738	$58,196	6.0%	$58,196	5.9%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

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Exhibit C

Line No.	Description	Pre Sch No.	Line No.
	(1)	(2)	
	Residential		
1	Residential	4	1
2	**Total Residential**		2
	Commercial & Industrial		
3	Gen. Svc. < 31 kW	23	3
4	Gen. Svc. 31 - 200 kW	28	4
5	Gen. Svc. 201 - 999 kW	30	5
6	Large General Service >= 1,000 kW	48	6
7	Partial Req. Svc. >= 1,000 kW.	47	7
8	Agricultural Pumping Service	41	8
9	Agricultural Pumping - Other	33	9
10	**Total Commercial & Industrial**		10
	Lighting		
11	Outdoor Area Lighting Service	15	11
12	Street Lighting Service	50	12
13	Street Lighting Service HPS	51	13
14	Street Lighting Service	52	14
15	Street Lighting Service	53	15
16	Recreational Field Lighting	54	16
17	**Total Public Street Lighting**		17
18	**Total Sales to Ultimate Consumers**		18
19	**Employee Discount**		19
20	**Total Sales with Employee Discount**		20
21	AGA Revenue		21
22	**Total Sales with Employee Discount and AGA**		22

[1] Excludes effects of the Low Income Bill Payment Ass
[2] Percentages shown for Schedules 48 and 47 reflect th

PUBLIC UTILITY COMMISSION
OF OREGON

UE 390

PACIFICORP

PAC/1610

Docket No. UE 216 Joint Testimony in Support of Stipulation

August 23, 2021

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 26, 2010

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

RE: **Docket UE 216** – Joint Testimony in Support of Stipulation

Enclosed for filing by PacifiCorp d/b/a Pacific Power (the Company) is an original and five copies of the Joint Testimony in Support of the Stipulation. The Stipulation was filed on July 7, 2010, on behalf of the Company, Oregon Commission Staff, the Citizens' Utility Board, the Industrial Customers of Northwest Utilities and Sempra Energy Solutions LLC. In a June 29, 2010 letter to Judge Power, the Company indicated that the joint testimony would be filed separately from the Stipulation.

If you have any questions, please contract Joelle Steward, Regulatory Manager, at (503) 813-5542.

Very truly yours,

Andrea L. Kelly /JB

Andrea L. Kelly
Vice President, Regulation

Enclosure

cc: UE 216 Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 216

In The Matter:

PACIFICORP, dba PACIFIC POWER 2011 Transition Adjustment Mechanism Schedule 201, Cost-Based Supply Service

STAFF-PACIFICORP-CUB-ICNU-SEMPRA

JOINT TESTIMONY IN SUPPORT OF STIPULATION

WITNESSES: KELCEY BROWN, GREGORY N. DUVALL, GORDON FEIGHNER,
RANDALL J. FALKENBERG, AND KEVIN C. HIGGINS

July 2010

Q. Who is sponsoring this testimony?

A. This testimony is jointly sponsored by Staff of the Public Utility Commission of Oregon (Staff), PacifiCorp (or the Company), the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Sempra Energy Solutions LLC (Sempra). In this Joint Testimony, the parties are referred to collectively as the "Parties."

Q. Please state your names.

A. Kelcey Brown, Gregory N. Duvall, Gordon Feighner, Randall J. Falkenberg and Kevin Higgins. Ms. Brown's qualifications are set forth in Exhibit Staff/101, Brown/1; Mr. Duvall's qualifications are set forth in PPL (TAM)/100, Duvall/1; Mr. Feighner's qualifications are set forth in CUB Exhibit/101; Mr. Falkenberg's qualifications are set forth in Exhibit ICNU/101; and Mr. Higgins' qualifications are set forth in SES/100.

Q. What is the purpose of this Joint Testimony?

A. This Joint Testimony describes and supports the stipulation filed in this proceeding on July 7, 2010 (Stipulation), between Staff, CUB, ICNU, Sempra, and PacifiCorp (referred to hereinafter jointly as the "Parties" and individually as a "Party).

Q. Does the Stipulation resolve all contested issues in this proceeding that were raised prior to the Company's rebuttal update?

A. Yes. The Stipulation is a comprehensive settlement of all issues in the Company's 2011 Transition Adjustment Mechanism (TAM) filing prior to the July 7, 2010 Rebuttal Update. The purpose of the TAM filing is to update net power costs (NPC) for 2011 and to set transition adjustments for Oregon customers who choose direct access in the November 2010 open enrollment window.

In addition to resolving certain issues in the 2011 TAM, the Stipulation includes provisions that: (1) set forth methodology changes that the Company will make in the 2012 TAM; (2) establish new procedures relating to the Indicative Filing and Final Update; (3) resolve issues related to forecast changes in Other Revenue for items that have a direct relation to NPC; (4) state that the Company will make certain filings with the Federal Energy Regulatory Commission (FERC); (5) state that the Commission's final decision in Docket UM 1355 will be reflected in the 2011 TAM if the decision is timely and issued before the Indicative Filing; (6) resolve ICNU's deferred accounting application in Docket UM 1465; (7) provide for a transmission-related credit to be included in the Schedule 294 transition adjustment for the 2011 TAM for Schedule 747 and 748; (8) resolve issues related to billing information and bill inquiries from direct access customers, and (9) commit the Parties to work collaboratively to consider a change in the TAM schedule for the annual filing.

Q. Have all Parties to the proceeding signed on to the Stipulation?

A. Yes.

Stipulated 2011 NPC Revenue Increase

Q. What was the Company's proposed increase to NPC revenues prior to this settlement?

A. The Company's February 26, 2010 TAM filing reflected an increase of approximately $69.2 million over the $256.1 million Oregon-allocated NPC baseline set in UE 207, adjusted for the loss of retail load.

Q. What do the Parties agree with respect to the Company's proposed 2011 TAM NPC revenue increase?

A. The Parties agree to reduce PacifiCorp's Oregon-allocated NPC by $11.0 million, as shown in Exhibit A to the Stipulation. This will result in an increase of $58.2 million to Oregon-allocated NPC, including the load change adjustment, based on the Company's initial filing. This increase results in 2011 NPC of approximately $1.233 billion on a total-Company basis, and $301.8 million on an Oregon-allocated basis, subject to updates described below.

Q. Does the stipulated reduction of $11.0 million resolve all issues raised by Parties as of the date of the Stipulation?

A. Yes. The Parties agreed that the $11.0 million reduction resolves all issues related to NPC as of the date of the Company's July 7, 2010 update, which was filed on the same date as the Stipulation. Specifically, the Stipulation reflects the issues raised in the testimony of Staff, ICNU, CUB, and Sempra; changes in NPC resulting from items specified in the Company's April 21, 2010 filing of corrections to and omissions from the Initial Filing; and certain other specific corrections in addition to those specified in the April 21, 2010 filing.

Q. Will the stipulated NPC be subject to the updates scheduled to be filed in this proceeding on November 8, 2010 and November 15, 2010?

A. Yes. As described in the TAM Guidelines, in addition to its Rebuttal Filing on July 7, 2010 that was filed on the same day as the Stipulation, the stipulated NPC will be updated in its Indicative Filing on November 8, 2010, and the Final Update on November 15, 2010 (collectively the Updates). The Parties agree that the Updates may increase or decrease the Oregon-allocated increase of $58.2 million from base NPC.

Q. Can Staff and intervenors challenge these Updates?

A. Yes. The Stipulation retains Staff's and intervenors' ability to challenge the Updates for new NPC elements (e.g., new or updated contracts), including those in the July 7, 2010 update. However, the Parties agree to not make additional error corrections or other changes relevant to the Company's filings made prior to the date of the Rebuttal Update. For example, no Party can identify new errors in data inputs that were included in PacifiCorp's original filing. All parties have agreed to accept the risk that there may be unidentified errors in the Company's original filing.

Q. What is the Parties' agreement for rate spread and rate design?

A. Rate spread is consistent with the TAM Guidelines and the stipulation adopted by the Commission in Docket UE 199. The proposed Schedule 201 revenues by rate schedule were determined by spreading the total forecast net power costs for the test year to the rate schedules in the same manner as the revenues for Schedule 200 were spread to the rate schedules in the Company's current general rate case, Docket UE 217. The rate spread agreed to by the Parties is set forth in Exhibit C to the Stipulation. For rate design, the Parties agreed that the Company will revise Schedule 4 rates in Schedule 201 to reflect the rate design agreed to by the parties in Docket UE 217. The stipulation resolving all issues in that docket was filed on July 12, 2010.

Q. How will PacifiCorp implement the rates resulting from the Stipulation?

A. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 201 rates and revised transition adjustment Schedules 294 and 295 as part of a compliance filing in Docket UE 216, to be effective January 1, 2011, reflecting rates as agreed in the Stipulation.

Procedures Related to the Indicative Filing and Final Updates

Q. Please describe the provisions in the Stipulation governing procedures related to the Indicative Filing and Final Update.

A. Paragraphs 13 and 14 of the Stipulation provide procedural requirements related to the Indicative Filing and Final Updates in this case and future TAM proceedings. First, the Company agrees to file an attestation with the Indicative Filing in this case and in future TAM filings confirming that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing. The attestation will also identify any exceptions and the reason why the Company excluded such contracts.

Second, the Stipulation sets forth procedures that will apply to challenges to the Company's Final Updates and compliance filing. These procedures will apply to this case and to the 2012 TAM filing. During the 2013 TAM filing, the Parties will review the effectiveness of the procedures.

Q. Please describe the procedures set forth in the Stipulation governing challenges to the Company's Final Updates and compliance filings.

A. The Stipulation provides that Staff and intervenors retain their procedural rights to raise any issue regarding the Company's Final Updates to the Commission prior to and during the Commission public meeting. The Parties have not reached any agreement on the appropriateness of a deferral filed after the Commission public meeting. Staff's and intervenors' procedural rights include filing for a deferral of costs related to the final TAM updates or requesting that a portion of the TAM be allowed subject to refund. To facilitate review of the Final Updates, PacifiCorp agrees to make a good faith effort to respond to all discovery requests after the Indicative Filing in five business days. If a Party has a concern with the Company's Final Update, it will provide notice of such concern to the Parties at least 10 business days before the Commission public meeting scheduled immediately prior to the effective date of the compliance filing. The notice will identify the specific elements of the Updates that are relevant to the potential challenge and provide an explanation of the Party's concern.

The Company will provide an initial response to the Parties regarding their concerns no more than five business days after receiving the notice. The Parties will work to reach resolution of the issue.

If the Parties cannot resolve the matter before the Commission public meeting, the Parties may make recommendations to the Commission at the public meeting to set a process to resolve the matter, if additional process is required. The recommendations may include that a specific amount of the tariff change will be subject to deferral until the Commission resolves the matter. For any additional process after the Commission public meeting, the Parties agree to request a schedule that will result in a Commission decision within 90 days of the effective date for new rates.

Q. Does the Stipulation specify whether PacifiCorp may oppose the filing of such a deferral?

A. Yes. The Stipulation provides that PacifiCorp will not oppose the filing of a deferral of any limited and specific cost that is identified by the Parties at least 10 business days before the Commission public meeting. In particular, the Company will not challenge the deferral on the basis that it fails to meet the Commission's standards for deferred accounting as initially set forth in Order No. 05-1070 (Docket UM 1147), including issues related to the materiality of the filing and a showing of substantial harm. PacifiCorp otherwise retains the right to object.

Q. How does the Stipulation propose that a Commission decision resulting in changes to the transition adjustments be handled?

A. The Stipulation specifies that if a final Commission decision on any challenges to the Final Update results in changes to the transition adjustments approved in Schedules 294 and 295, the Company may reflect in the direct access balancing account any difference between the approved transition adjustments and the transition adjustments that would have been in effect consistent with the Commission's decision on the challenged items. Language in Schedules 294 and 295 will be revised in the Company's compliance filing to reflect this change.

Methodology Changes in the 2012 TAM

Q. Does the Stipulation include terms related to the methodology the Company will use in the 2012 TAM?

A. Yes. Although the Parties specified that the stipulated $11 million reduction to the Oregon-allocated baseline NPC does not imply the Parties' agreement on the merits of any adjustment or the Company's NPC study, Paragraph 8 of the Stipulation identifies methodological changes that the Company agrees to reflect in the 2012 TAM. The Company will provide Parties with the details of these changes by mid-January 2011 and will meet with Parties to discuss the changes if requested. Staff and intervenors reserve the right to review, challenge, and propose alternatives to these methodological changes.

Q. What are the methodological changes that will be incorporated in the 2012 TAM?

A. The Company agreed to revise its daily screening methodology, use a four-year average for the costs of purchased power from the Black Hills combustion turbines, rely on the traditional analysis of four years of actual data to derive heat rate inputs without adjustments for scrubbers or other capital projects, model the purchased power from the Arizona Public Service under the supplemental contract for coal and other generation to be exercised only when economic, not include inter-hour wind integration charges for non-owned wind facilities, and include modeling of non-firm transmission links and costs and capacity using a four-year average.

Q. Will the Company include these methodological changes in TAM filings after the 2012 TAM?

A. Yes, unless the Company identifies a change in facts or circumstances.

Other Revenue

Q. Does the Stipulation include a provision relating to accounting for changes in Other Revenue in the TAM?

A. Yes. The Stipulation provides that in future stand-alone TAM filings, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 217.

Q. Does the Stipulation establish revenue baselines for certain Other Revenue items?

A. Yes. Exhibit B contains the revenue baselines from Docket UE 217 for the storage and exchange agreements for Seattle City Light Stateline and the non-Company owned Foote Creek projects, revenues from the Bonneville Power Administration associated with the South Idaho Exchange, steam revenues for Little Mountain and royalty offset revenues for the Georgia Pacific Camas contract.

FERC Filings

Q. How does the Stipulation resolve the issue of wind integration services to non-owned facilities not being reflected in the Company's Open Access Transmission Tariff approved by FERC?

A. In the Company's next rate case filing with FERC, the Company agrees to file to modify the Company's Open Access Transmission Tariff to include charges for wind integration services to non-owned wind facilities. The Company's next FERC rate case is scheduled to be filed in June 2011.

Q. Does the Stipulation contain any other provisions relating to the Company's next FERC rate case filing?

A. Yes. The Company has agreed to update line loss charges in its next FERC rate case.

Q. Does this prevent parties from raising these issues in their testimony in next year's TAM?

A. No. In addition, the Parties do not have to support PacifiCorp's FERC filing, and can propose alternative treatments of wind integration service to non-owned facilities and line loss charges in future TAMs and/or FERC filings.

Docket UM 1355 – Investigation in Forced Outage Rates

Q. How do the Parties propose treating the Commission's decision in Docket UM 1355 in the Company's 2011 TAM?

A. The Stipulation provides that if the Commission's decision in that proceeding is timely and issued prior to the Indicative Filing, the Company agrees to reflect the final Commission decision in the 2011 TAM. PacifiCorp will implement the final Commission decision in UM 1355, even if a party in UM 1355 seeks rehearing, reconsideration or appeal of the Commission decision. The Parties clarified that the provision relating to UM 1355 does not expressly or impliedly waive PacifiCorp's rights, including but not limited to the right to seek clarification or challenge the UM 1355 decision or to seek to have the impact of the decision made subject to refund or deferral.

Docket UM 1465 – ICNU's Application for Deferral Accounting for 2010 TAM

Q. Please provide a short summary of the issues raised in Docket UM 1465.

A. In UM 1465, ICNU filed an Application for Deferred Accounting requesting that the Commission require PacifiCorp to defer certain power costs, benefits, and revenues associated with certain contracts associated with the 2010 TAM, UE 207. ICNU objected to the Company's treatment of the relevant contracts in the Final Update in that case.

Q. Does the Stipulation resolve Docket UM 1465?

A. Yes. ICNU agrees to dismiss and not refile its deferred accounting application in that docket. This withdrawal is based upon the Company's ability under UP 260 to sell Oregon-allocated renewable energy credits (RECs) ineligible under Oregon's renewable portfolio standard that are generated in 2010 under the terms of the NV Energy contract and the LADWP contract, with net proceeds to be credited to the property sales balancing account. Although PacifiCorp temporarily suspended sales of Oregon-allocated RECs under these two contracts upon receipt of the Commission's order in UE 210, the terms and conditions of the contracts allow PacifiCorp the flexibility to ensure that Oregon customers will receive a full allocation (using the System Generation or SG factor) of the revenues received from these contracts in 2010.

Schedules 294 and 295 Transition Adjustment

Q. What did the Parties agree in regards to the calculation of the transition adjustments in Schedules 294 and 295 for direct access?

A. PacifiCorp agrees to increase the Schedule 294 transition adjustment by

$(0.50)/MWh for the 2011 TAM for Schedule 747 and 748 customers. This increase reflects the potential value associated with reselling Bonneville Power Administration (BPA) Point to Point (PTP) wheeling rights from Mid-C to the Company's Oregon Service territory that are freed-up as a result of customers choosing direct access.

Q. **What else did the Stipulation provide with respect to BPA PTP wheeling rights?**

A. PacifiCorp also agrees to meet with an Energy Service Supplier (ESS) upon request in advance of the November 2010 shopping window to discuss price, terms and potential quantities of BPA PTP wheeling rights to be purchased from PacifiCorp for delivery from all points of receipt considered to be Mid-C to the Company's Oregon service territory to serve direct access load. The Stipulation provides that PacifiCorp will evaluate this issue using the actual direct access customer data that results from the November 2010 shopping window, report its findings back to the parties, and use any knowledge gained to guide its filing of the 2012 TAM.

Q. **Does the Stipulation require PacifiCorp to sell transmission rights to an ESS?**

A. No. The Stipulation states that PacifiCorp is not obligated to sell any transmission rights to an ESS.

Direct Access Billing Issues

Q. Please explain the provisions in the Stipulation related to billing of potential direct access customers.

A. The Stipulation states that PacifiCorp will continue to respond as appropriate to individual bill inquiries by direct access customers. If a participating direct access customer requests additional information on an on-going basis, the Company will endeavor to provide such information as practicable, consistent with Schedule 300, Rule 11-2. Schedule 300, Rule 11-2 provides that the Company may charge the actual costs of work to be performed at a customer's request. The Stipulation clarifies that this provision does not prejudge the appropriateness of application of Schedule 300, Rule 11-2 in these circumstances. For example, there may be disagreement among the Parties about whether Schedule 300, Rule 11-2 should apply to additional information that may be provided to direct access customers.

Q. What other billing issues does the Stipulation address?

A. In addition to the provisions related to individual bill inquiries, the Stipulation provides that prior to the November 2010 shopping window, PacifiCorp will work with interested Parties to identify the billing information that PacifiCorp's Customer Service System billing system can provide on a routine basis to direct access customers sufficient to allow such customers to reconcile their bills to the PacifiCorp tariff. If the Parties cannot resolve this issue by the start of the 2011 shopping window, the Parties agree to support establishing a collaborative process to address this issue.

Future TAM Filing Schedule

Q. Please explain the provision in the Stipulation regarding the schedule for future TAM filings.

A. The Parties agree to work together to develop a proposal by fall of 2010 to consider a change to PacifiCorp's TAM schedule from an annual filing with a rate effective date of January 1 to an annual filing with a rate effective date of July 1. The Parties agree to work in good faith to reach agreement in a timeframe that will avoid the Company filing on March 1, 2011 for the next TAM and general rate case. The proposal will consider mechanisms to mitigate financial impacts to PacifiCorp due to a potential six-month delay during the transition period.

Commission Rejection or Modification of the Stipulation

Q. If the Commission rejects any material part of the Stipulation, are the Parties entitled to reconsider their participation in the Stipulation?

A. Yes. The Stipulation provides that if the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party shall have the rights provided in OAR 860-014-0085, including the right to withdraw from the Stipulation, and shall be entitled to seek reconsideration or appeal of the Commission's Order.

Reasonableness of the Stipulation

Q. Have the Parties evaluated the overall fairness of the Stipulation?

A. Yes. Each Party has reviewed the calculation of the 2011 NPC revenue increase and the rates resulting from this increase. The Parties agree that the rates that would result from the issues resolved in this Stipulation would be fair, just, and reasonable based on their respective case positions, the positions of other Parties, and the discovery produced in this proceeding by the Company. Because the July update has not been reviewed, the final updates have not been filed and the final TAM rates are unknown, the parties have not yet reached agreement that the final TAM rates will be fair, just and reasonable. The Parties also agree that the results of the other issues resolved in the Stipulation are fair and reasonable and should be adopted.

Q. What do the Parties recommend regarding the Stipulation?

A. The Parties recommend that the Commission adopt the Stipulation as the basis for resolving issues in this proceeding and include the terms and conditions of the Stipulation in its order in this case.

Q. Does this conclude your Joint Testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on this 26th of July, 2010, I caused to be served, via E-Mail and overnight delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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PUBLIC UTILITY COMMISSION OF OREGON

UE 390

PACIFICORP

PAC/1611

Docket No. UE 374 Excerpt from AWEC/100 Opening Testimony of Bradley G. Mullins

August 23, 2021

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

June 4, 2020

Q. WOULD PACIFICORP'S PROPOSED APCA SIMPLIFY RECOVERY OF NPC?

A. No, the APCA would undoubtedly be more controversial that the current TAM. The current TAM/PCAM structure substantially mitigates issues associated with the prudence of PacifiCorp's actual power costs because most deviations from the forecast (up or down) are captured in the deadbands. With PacifiCorp's proposed dollar-for-dollar recovery of NPC, the Company's actual power costs will need to be extensively reviewed. Despite this, PacifiCorp proposes to give parties and the Commission even less time to review these costs than they have to review the Company's forecasts in the TAM, despite the TAM already being an abbreviated proceeding. This will not result in just and reasonable costs for customers and is not in the public interest.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE APCA PROPOSAL PRESENTED BY PACIFICORP.

A. I recommend that the Commission reject PacifiCorp's proposal to replace the TAM and PCAM with the APCA. As I have discussed, the TAM/PCAM framework is operating as intended by the Commission. PacifiCorp's proposal places the burden of the normal business risk of a utility at the feet of ratepayers, thereby removing the incentive to the Company to effectively manage costs.

IX. TAM GUIDELINES

Q. PLEASE DETAIL THE PROPOSED APCA GUIDELINES' MODIFICATIONS AS COMPARED WITH THE EXISTING TAM GUIDELINES.

A. Exhibit PAC/501, attached to PacifiCorp Witness Michael Wilding's Direct Testimony, provides a redlined draft of the APCA guidelines as proposed by PacifiCorp. Because I recommend that the Commission reject the APCA, I also recommend that the Commission reject these changes to the TAM Guidelines. Some of PacifiCorp's proposed changes, however, could be incorporated into the existing TAM, and it is unclear from PacifiCorp's testimony whether the Company is proposing to make these changes in the event the Commission maintains the TAM. Should the Commission entertain the proposal in such a manner, I address these changes below and recommend an additional change to the TAM Guidelines going forward.

Q. HOW DOES PACIFICORP PROPOSE TO CHANGE THE INITIAL TAM FILING?

A. PacifiCorp first proposes to modify the substance of the notice provided to stakeholders regarding changes to the forecast modeling. Currently, PacifiCorp is required under the guidelines to provide a review of any proposed changes to the net power cost model, as well as a side-by-side comparison of the prior year net power costs with and without the proposed model changes, where such a comparison is practical.

In the proposed APCA framework, PacifiCorp proposes to only require notice of "substantial changes to the [methods] used to forecast" net power costs.[107/] There is no clarity as to what is a "substantial change". Presumably, PacifiCorp would make the subjective determination regarding the substantial nature of any change, leaving "unsubstantial" changes unhighlighted, thereby increasing the likelihood that they would go unreviewed by stakeholders and, ultimately, the Commission. I recommend this additional discretion not be afforded to PacifiCorp; rather all changes to the modeling methods should continue to be identified in the pre-filing notice.

[107/] Exhibit PAC/501, Wilding/ at 15.

Q. PLEASE CONTINUE WITH YOUR DISCUSSION OF PACIFICORP'S PROPOSED CHANGES TO THE INITIAL FILING UNDER THE TAM GUIDELINES.

A. The current TAM guidelines prohibit PacifiCorp from making modeling changes in a stand-alone TAM filing if Staff, CUB or AWEC objects. PacifiCorp proposes to eliminate this prohibition related to stand-alone TAM/APCA filings.

Q. WHAT DO YOU RECOMMEND?

A. I recommend retaining the existing, agreed upon, language in the TAM guidelines.

Q. DOES PACIFICORP PROPOSE CHANGES TO THE TAM GUIDELINES REGARDING THE REBUTTAL FILING?

A. Yes. Currently, the TAM guidelines prohibit PacifiCorp from updating its forecast net power costs to address changes in coal costs for mines directly or indirectly owned by PacifiCorp. PacifiCorp's current proposal would eliminate this prohibition and specifically include updates for coal contracts for mines directly or indirectly owned by PacifiCorp to be allowed to be updated in a rebuttal filing.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission retain the prohibition against updating coal costs related to mines owned by PacifiCorp. PacifiCorp should be incented to manage the costs associated with its vertically integrated coal supply, and should not be allowed to modify the initial estimated costs associated with these integrated coal sources after the initial filing.

Q. DOES PACIFICORP PROPOSE CHANGES TO THE TAM GUIDELINES REGARDING THE FINAL UPDATE?

A. Yes, PacifiCorp proposes two modifications, one to the calculation of the Transition Adjustment and one to the rate design for Schedule 200. For the Transition Adjustment calculation, PacifiCorp proposes to modify the stipulation adopted in Order 08-543 "so that any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the California-Oregon Border (COB) price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID."[108/] For the rate design, PacifiCorp proposes to modify the Schedule 200 Supply Service rate design from an energy only $/kWh rate to a two-part rate with a $1.00/billing kW demand charge and a $/kWh energy charge.[109/]

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE CHANGE TO THE TRANSITION ADJUSTMENT CALCULATION?

A. If the Commission adopts PacifiCorp's recommended change, I recommend that this guideline also require PacifiCorp to include the impact of the DART adjustment in the calculation. This will ensure a more accurate calculation of the transition charge.

Q. WHAT DO YOU RECOMMEND REGARDING THE PROPOSED CHANGE TO THE SCHEDULE 200 RATE DESIGN?

A. It is unclear what the purpose of PacifiCorp's change is. To the extent PacifiCorp proposing to allow rate design changes in the TAM, such as modifying the energy charge differential for Schedules 47/48, the Commission should deny this request. Rate design changes should only be allowed in a general rate case.

Q. DOES PACIFICORP PROPOSE CHANGES TO THE GUIDELINES REGARDING A TAM/APCA FILING MADE CONCURRENTLY WITH A GENERAL RATE CASE?

A. Yes. Currently, if PacifiCorp files both a TAM and a General Rate Case proceeding in the same year, both filings must be made no later than March 1. PacifiCorp proposes to modify the timing requirement to allow for the discretion to file an APCA concurrently with a General

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108/ Id. at 19.
109/ Id. at 19-20.

Rate Case ("GRC") filed before May 15, or to delay the APCA filing until May15 if the GRC filing is made earlier in the year.[110/]

Q. WHAT DO YOU RECOMMEND?

A. I recommend maintaining the current requirement that a TAM filing be made concurrently with a GRC filing, should a GRC be filed. The Company's proposal would allow the Company to file a GRC early in the year and delay filing the corresponding APCA until May 15. This results in inefficiencies in addressing issues that are common between the filings. The current filing requirement should be maintained.

Q. WHAT CHANGES DO YOU PROPOSE TO MAKE TO THE TAM FILING REQUIREMENTS?

A. I propose two changes to the TAM filing requirements. First, PacifiCorp should provide all workpapers, including confidential information, contemporaneous to PacifiCorp's initial filing. Under the current approach the workpapers are provided over a 15-day period. Given that the TAM is already operating under an accelerated schedule, having a 15-day delay in receiving the necessary workpapers makes it challenging for parties to review PacifiCorp's filing under the compressed schedule. Further, one would expect that PacifiCorp's workpapers are already completed at the time it files its testimony, so this requirement would not impose any additional burden on PacifiCorp.

Second, all testimony and workpapers should be posted to Huddle or emailed via encrypted zip. It is outdated, wasteful, and causes delays to send workpapers on physical media, such as a CD. Accordingly, AWEC recommends the Commission encourage file sharing where possible and practicable

110/ Id. at 21-22.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

PACIFICORP

PAC/1612

Docket No. UE 374 Excerpt from AWEC/500 Rebuttal Testimony of Lance D. Kaufman

August 23, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

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Request for a General Rate Revision.	)
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REBUTTAL TESTIMONY OF LANCE D. KAUFMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

July 24, 2020

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance Kaufman. I am the principal economist of Aegis Insight. My qualifications are included in Exhibit AWEC/301. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").

Q. ARE YOU THE SAME LANCE KAUFMAN WHO FILED OPENING TESTIMONY AND REBUTTAL/CROSS ANSWERING TESTIMONY ON DECOMMISSIONING COSTS FOR AWEC?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I respond to PacifiCorp, dba Pacific Power's ("PacifiCorp" or "Company") Reply Testimony as well as the Opening Testimony of Oregon Public Utility Commission ("Commission") Staff and the Oregon Citizens' Utility Board ("CUB").

Q. HAVE THERE BEEN ANY DEVELOPMENTS SINCE PACIFICORP FILED REPLY TESTIMONY?

A. Yes. The parties to this docket have reached a settlement in principle on all rate spread and rate design issues. Accordingly, my testimony does not address these issues.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I make the following recommendations in my testimony:

1. Find the cost of PacifiCorp's Jim Bridger Units 3 and 4 SCR and Hunter Unit 1 Baghouse and SCR investments not prudent. Exclude the associated costs from rates.
2. Use the decommissioning and remediation costs originally filed in UM 1968. If the Commission relies on the Kiewit decommissioning study, include AWEC's proposed adjustments, as modified in this Rebuttal Testimony.

3. Reject PacifiCorp's proposal to offset the unrecovered investment in Cholla Unit 4 with Tax Cuts and Jobs Act ("TCJA") benefits; additionally, exclude certain costs associated with Cholla from rates, as initially recommended by Bradley G. Mullins and modified in this Rebuttal Testimony.
4. Exclude certain costs associated with the Deer Creek Mine closure, as initially recommended by Mr. Mullins and modified in this Rebuttal Testimony.
5. Reject PacifiCorp's Annual Power Cost Adjustment ("APCA") proposal.
6. Condition the prudence of the Energy Vision 2020 Projects and transmission on the cost and benefit commitments identified in Mr. Mullins' testimony.
7. Reject PacifiCorp's wildfire mitigation cost recovery mechanism; alternatively, condition cost recovery under any approved mechanism on an earnings test.
8. Modify the TAM guidelines to require PacifiCorp to provide most workpapers concurrently with its initial annual filing.
9. Consider CUB's recommendation for a non-bypassable charge on direct access to recover coal plant decommissioning costs in UM 2024.

Q. ARE YOU ADDOPTING PREVIOUSLY FILED TESTIMONY IN THIS CASE?

A. Yes. I am adopting the Opening Testimony of Bradley Mullins.

Q. HOW HAVE YOUR RECOMMENDATIONS CHANGED RELATIVE TO OPENING TESTIMONY?

A. I have reviewed PacifiCorp's rebuttal testimony related to the issues that I raised or adopted from Mr. Mullins. I also reviewed related testimony from Staff, Citizens' Utility Board ("CUB"), and Sierra Club. As a result of this review, I withdraw some recommendations where the concerns raised in Opening Testimony have been resolved. I also modify or provide alternate recommendations for issues where PacifiCorp's reply

VI. ANNUAL POWER COST ADJUSTMENT

Q. PLEASE SUMMARIZE AWEC'S RECOMMENDATION IN ITS OPENING TESTIMONY ON PACIFICORP'S ANNUAL POWER COST ADJUSTMENT.

A. AWEC opposed PacifiCorp's Annual Power Cost Adjustment ("APCA"), which would allow dollar-for-dollar recovery of PacifiCorp's net power costs ("NPC"). AWEC argued that this mechanism was contrary to Commission policy that provides for a sharing of risk in NPC variances between customers and shareholders through the existing Power Cost Adjustment Mechanism ("PCAM"). AWEC also showed that the APCA is nothing more than PacifiCorp's attempt to relitigate issues the Commission has rejected multiple times before.[51] Commission Staff and the Oregon Citizens' Utility Board similarly oppose the APCA.[52]

Q. HOW DOES PACIFICORP RESPOND TO AWEC'S AND OTHER PARTIES' ARGUMENTS AGAINST THE APCA?

A. PacifiCorp's primary argument seems to be that circumstances have changed since it previously requested modifications to the PCAM, and that now is the right time for the Commission to revisit its principles underlying the existing PCAM structure. Specifically, PacifiCorp claims that variable renewable generation is difficult to forecast accurately, and the increased penetration of this generation, driven both by economics and state/regional policies, will exacerbate NPC forecast errors.[53]

Q. IS PACIFICORP'S POSITION SUPPORTED BY THE EVIDENCE?

A. No. It is certainly true that the amount of variable generation in PacifiCorp's portfolio, and in the West generally, has increased and will continue to increase in the future. It is

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[51] AWEC/100, Mullins/27:1-37:17.
[52] Staff/1300, Gibbens/9:1-41:18; CUB/100, Jenks/30:3-45:3.
[53] PAC/2000, Wilding/56:18-57:13; PAC/3000, Graves/14:9-15:4.

Q. PLEASE DESCRIBE THE COSTS INCURRED AS A RESULT OF THE EXTENDED CLOSURE PERIOD.

A. Nearly all the costs between 2016, the original closure date, and 2018, the actual closure date, were labor costs or payments to the PacifiCorp subsidiary East Mountain Energy.[49/] Costs included PacifiCorp management fees, incentive payments, bonuses, and awards.

Q. GIVEN THAT COST OVERRUNS WERE THE RESULT OF FAULTY PLANS, AND THAT THEY INCLUDE PRIMARILY PAYMENTS TO SUBSIDIARIES, INCENTIVES, AND BONUSES, IS THE OVERAL COST-BENEFIT OF THE CLOSURE RELEVANT?

A. No. The Commission should focus on why there were cost overruns and whether the additional costs are appropriately included in rates.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS ISSUE?

A. I adopt Mr. Mullins' recommendation that PacifiCorp's recovery for closure costs be capped at the amount assumed in UM 1712.

Q. PLEASE SUMMARIZE THE COAL LEASE ABANDONMENT ROYALTY ISSUE.

A. In Opening Testimony, Mr. Mullins recommended excluding future royalty costs from rates. PacifiCorp can defer these costs if PacifiCorp incurs them. PacifiCorp appears to agree that royalty costs are uncertain and testifies that it "does not have a specific time line of when actual royalty obligations will be settled."[50/] I adopt Mr. Mullins' recommendation to exclude these costs from rates at this time.

49/ AWEC/504.
50/ PAC/3100, McCoy/45:17-18.

not true, however, that this shift has made it more difficult for PacifiCorp to forecast its NPC overall or exacerbated the Company's under-recovery of NPC. In fact, the opposite has occurred.

PacifiCorp provides its forecasted and actual NPC for the previous twelve years in Table 6 on page 55 of Mr. Wilding's testimony. That data shows that, for the six years between 2008 and 2013, deviations between forecasted and actual NPC averaged \$27,249,869. For the six-year period between 2014 and 2019, by contrast, deviations between forecasted and actual NPC averaged \$19,023,974. In fact, using the data from Table 7 on page 65 of Mr. Wilding's testimony, one can see that PacifiCorp's forecasts over the 2014-2019 period improved even without incorporating the effects of the day ahead/real time ("DART") adjustment – the average deviation was \$24,329,420, still \$3 million less on average than the deviations the Company experienced between 2008 and 2013. This improvement occurred even as PacifiCorp was "add[ing] 4,789 MW of new renewable resources."[54/] It is also in spite of the fact that: (1) PacifiCorp's NPC was approximately \$45 million higher on average over the latter six-year period than the earlier six-year period (thus allowing for the potential for greater deviations from the forecast); and (2) a portion of the latter six years of data also includes EIM transactions and production tax credits, which the earlier six-year period did not (thus also creating the potential for greater deviations from forecast). In other words, PacifiCorp's own data contradicts its primary argument that increased renewable penetration will lead to greater NPC forecast errors.

54/ PAC/2000, Wilding/59:15.

Q. HOW DOES AWEC'S PROPOSAL FOR EV 2020 PERFORMANCE REQURIENTS AFFECT VARIABILITY OF POWER COSTS?

A. In Opening Testimony Mr. Mullins recommended performance guarantees for the EV 2020 projects. This recommendation should offset PacifiCorp's concerns related to renewable generation variability.

Q. IS PACIFICORP'S POSITION CONTRADICTED BY ANY OTHER DATA?

A. Yes. PacifiCorp's testimony glosses over important historical context for the development of the current PCAM.[55/] Both PacifiCorp's and Portland General Electric Company's ("PGE") existing PCAMs have their origin in Commission Order 05-1261, in which the Commission rejected a stipulation to create a PCAM for PGE's hydro generation.[56/] In its decision, the Commission noted the significant annual variability of hydro generation.[57/] Such variability warranted "a mechanism to adjust PGE's rates for variations in hydro-related costs … *if it is reasonably designed.*"[58/] The Commission then identified four criteria for a properly designed PCAM: "(1) Limited to Unusual Events; (2) No Adjustments if Overall Earnings are Reasonable; (3) Revenue Neutrality; and (4) Long-Term Operation."[59/] Staff's Opening Testimony discusses these criteria in detail.[60/] Later in UE 180, the Commission used these criteria to develop a PCAM for PGE that applied to its total power costs,[61/] which is the same PCAM in existence today for both PGE and PacifiCorp. The variability of hydro generation, however, was the initial instigator for the development of these PCAMs.

55/ PAC/3000, Graves/5:1-19.
56/ Docket Nos. UE 165/UM 1187, Order No. 05-1261 (Dec. 21, 2005).
57/ Id. at 8.
58/ Id. (emphasis added).
59/ Id.
60/ Staff/1300, Gibbens/12:19-20:11.
61/ Docket Nos. UE 180/UE 181/UE 184, Order No. 07-015 at 26-27 (Jan. 12, 2007).

Q. WHY IS THIS HISTORY RELEVANT TO PACIFICORP'S APCA?

A. Because intermittent renewable generation has been shown to be no more variable than hydro generation. In UM 1662, AWEC's testimony showed that the year-to-year variability of PacifiCorp's wind generation between 2008 and 2013 had a relative standard deviation of approximately 11%.[62] Meanwhile, over that same period, the relative standard deviation of the variability in PacifiCorp's hydro output was 14%.[63] Consequently, the variability of renewable resources is not a basis to deviate from a PCAM structure that was created specifically to address similar variability in hydro. It is a basis to maintain this structure.

Q. HOW DO YOU RESPOND TO PACIFICORP'S ARGUMENT THAT OTHER NORTHWEST UTILITIES THAT HAVE OVER-FORECAST THEIR NPC IN RECENT YEARS ARE DISINGUISHABLE FROM THE COMPANY?

A. PacifiCorp's position in its Opening Testimony was that the NPC forecasting challenges it faces are not due to constraints on its own modeling software but are caused by market dynamics that are inherently impossible to forecast and that tend to impose incremental costs on PacifiCorp, thus leading to systematic under-recovery of NPC.[64] AWEC argued in Opening Testimony that, if this were the case, one would expect all utilities to under-forecast their power costs, as they all are subject to the same market dynamics. Both PGE and Avista in Washington, however, have over-forecast their power costs in recent years.[65]

PacifiCorp argues in response that these utilities are different because they have different generation portfolios. This is undoubtedly true, but that is not the argument

[62] AWEC/502 at 3.
[63] Id.
[64] PAC/600, Graves/3:14-6:16.
[65] AWEC/100, Mullins/35:14-36:9.

PacifiCorp has made to justify the APCA. Indeed, PacifiCorp's Reply Testimony contradicts itself in attempting to distinguish the Company from other utilities. On the one hand, Mr. Wilding argues that Avista is distinguishable from PacifiCorp due to the large amount of hydro generation in its portfolio, as compared to intermittent renewables,[66] while on the other hand, Mr. Graves claims that "the main problem that PacifiCorp faces is not the forecasting model itself. Rather, it is the inherent difficulty in forecasting one year in advance of the hourly demand and prices of purchases and sales, as well as the generation profile of renewable resources, *including hydropower*."[67] The reality is that, if PacifiCorp is indeed facing a systematic under-forecast of NPC, the problem almost surely lies in its power cost model, GRID, not inescapable and unpredictable market forces to which all utilities are subject.

Q. AWEC AND STAFF ALSO ARGUED THAT NOW IS NOT THE RIGHT TIME TO IMPLEMENT THE APCA BECAUSE PACIFICORP INTENDS TO REPLPACE GRID WITH A NEW NPC FORECASTING MODEL. HOW DOES PACIFICORP RESPOND?

A. PacifiCorp claims that that the energy landscape is constantly changing, and therefore acceptance of this argument would mean that "there will always be a reason to stand in the way of updating [the PCAM]."[68] There is a substantial difference, however, between the evolution of the generation mix or even changes to energy markets, which can be incorporated into and accommodated by power cost forecasting models (as PacifiCorp's assimilation of EIM benefits into its NPC forecasts demonstrates), and the creation of an entirely new power cost forecasting model. AWEC's position, which appears to be shared by Staff and CUB, is that to the extent PacifiCorp faces systematic NPC under-

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66/ PAC/2000, Wilding/72:7-73:3.
67/ PAC/3000, Graves/30:6-9 (emphasis added).
68/ PAC/2000, Wilding/68:10-11.

recovery, this is most likely due to the Company's modeling software, not market forces. PacifiCorp's change to a new forecasting model offers the ideal opportunity to test which theory is correct. Only after the Commission has this information should it consider changes to the PCAM, particularly ones as drastic as PacifiCorp has proposed.

VII. ENERGY VISION 2020

Q. PLEASE SUMMARIZE AWEC'S RECOMMENDATION IN ITS OPENING TESTIMONY ON THE ENERGY VISION 2020 PROJECTS.

A. AWEC recommended that the prudence of PacifiCorp's decision to invest in the Energy Vision 2020 ("EV 2020") projects be subject to the following conditions to better ensure customer benefits are realized from an economic resource procurement: (1) a hard cap on capital and O&M costs; (2) a hard cap on costs for the D.2 segment of the Energy Gateway transmission project; (3) a guarantee of full PTC and energy benefits from the EV 2020 projects; and (4) a minimum capacity factor for each resource at the level modeled in the RFP bids. These conditions reflect both the Commission's acknowledgment order of PacifiCorp's 2017 IRP and recommendations from the Oregon Independent Evaluator ("IE") overseeing the RFP.

Q. HOW DID PACIFICORP RESPOND IN REPLY TESTIMONY?

A. PacifiCorp generally opposes AWEC's conditions on the prudence of the EV 2020 projects. The Company argues that the EV 2020 projects were pursued not solely for economic reasons, but to meet an energy and capacity need that would otherwise be filled with front office transactions ("FOTs").[69] It also accuses AWEC of "selectively rel[ying] on the Oregon independent evaluator's report" and defends its RFP modeling.[70]

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[69] PAC/2300, Link/53:11-57:3.
[70] Id. at 57:4-61:18.