PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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July 9, 2021

VIA ELECTRONIC FILING

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

Re: UE 390—PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Douglas R. Staples, Seth Schwartz, Dana M. Ralston, Daniel J. MacNeil, Mary M. Wiencke, and Robert M. Meredith.

Included with this filing are electronic workpapers, which have been uploaded to Huddle. Confidential and highly confidential material in support of the filing has been provided to parties under Order No. 16-128 and Order No. 21-086.

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

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosures

CERTIFICATE OF SERVICE

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

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UE 390

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Dated this 9th day of July, 2021.

Katie Savarin
Katie Savarin
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 390
Exhibit PAC/100
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Douglas R. Staples

July 2021

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ATTACHED EXHIBITS

Exhibit PAC/401—2022 TAM Oregon-Allocated Net Power Costs Reply Filing

Exhibit PAC/402—2022 Results of Updated Net Power Cost Study Reply Filing

Exhibit PAC/403—2022 Updates Summary Reply Filing

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Douglas R. Staples and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am currently employed as the Net Power Cost Advisor in the Net Power Costs Group.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science degree with a focus on finance from the University of South Florida. I began working for PacifiCorp in early 2015, and during my tenure at PacifiCorp, I have worked as a senior risk management analyst and I currently work as a net power cost advisor. In that role, I am responsible for leading and overseeing all modeling efforts associated with the Company's net power costs (NPC) and various other regulatory filings using Generation and Regulation Initiative Decision Tools (GRID) and AURORA. Before my time with PacifiCorp, I spent seven years working as a senior risk analyst and a supervisor of the risk management group at NextEra Energy Power Marketing, where I designed reports, provided validation and troubleshooting of risk metrics, and oversaw the quarterly validation of valuation assumptions used in mark to market accounting for financial statements. Prior to that, I worked as a principal business analyst for San Diego Gas & Electric. In that role, I was a part of the acting arm of the risk management committee, providing oversight to both San Diego Gas & Electric Company and Southern California Gas Company.

Q. Did you offer direct testimony in this Docket?

A. No. I am, however, adopting the direct testimony of Mr. David G. Webb.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony in Washington.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony has two sections. First, I provide a Transition Adjustment Mechanism (TAM) update (Reply Update), as allowed under TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363.[1] In the Reply Update, I explain the reasonableness of the Company's updated Oregon NPC of $1,439 million for the test period of the 12 months ending December 31, 2022.[2] This results in a rate increase of $1.7 million compared to the rate increase of $1.2 million proposed in the Company's April 1, 2021, filing (Initial Filing). I provide corrections and contract, fuel, and forward price curve updates to the Company's Initial Filing.

Second, my reply testimony responds to various issues and adjustments raised in the opening testimony of Commission Staff (Staff) witnesses Ms. Moya Enright, Ms. Heather Cohen, Ms. Nadine Hanhan, Mr. Brian Fjeldheim, Ms. Kathy Zarate, Mr. John Fox, Ms. Rose Anderson, Mr. Curtis Dlouhy, and Mr. Scott Gibbens;

[1] *In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274, at 7 (July 16, 2009) [hereinafter 2009 TAM]; *In the Matter of PacifiCorp, dba Pacific Power 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 at 3-4 (Oct. 30, 2009) [hereinafter 2010 TAM]; *In the Matter of PacifiCorp, dba Pacific Power 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 at 4-5 (Sept. 16, 2010) [hereinafter 2011 TAM].

[2] Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis.

Alliance of Western Energy Consumers (AWEC) witness Mr. Bradley G. Mullins; Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks; and Sierra Club witness Mr. Ed Burgess.

Q. Please identify the witnesses providing reply testimony supporting the 2022 TAM.

A. In addition to my testimony, the following additional other witnesses are providing reply testimony in support of the Company's 2022 TAM filing:

- Mr. Seth Schwartz, President, Energy Ventures Analysis, Inc., provides testimony which discusses how utilities purchase coal and the prudence of PacifiCorp's coal supply agreements.
- Mr. Dana M. Ralston, Senior Vice President of Thermal Generation and Mining, testifies in support of the prudence of the Company's coal supply agreements (CSAs) and their consistency with industry standards and confirms that the Company's use of incremental costs for dispatch of coal plants reflects industry practice and is beneficial to customers.
- Mr. Daniel J. MacNeil, Commercial Analytics Adviser, responds to testimony regarding the Company's analysis of potential alternatives undertaken related to the Hunter coal supply agreement.
- Ms. Mary M. Wiencke, Vice President, Transmission Regulation and Market Policy, provides testimony to address Staff's concerns regarding PacifiCorp's compliance with California cap-and-trade regulations.
- Mr. Robert M. Meredith, Director, Pricing and Cost of Service, responds to the concerns raised by the Small Business Utility Advocates (SBUA) and addresses the

calculation of the Consumer Opt-Out Charge in response to the testimony of Calpine Energy Solutions, LLC (Calpine).

Q. Please summarize your reply testimony.

A. I demonstrate the reasonableness of PacifiCorp's NPC in the 2022 TAM, which represents a rate change of $1.7 million, through the following points:

- Consistent with Commission precedent, the goal of the TAM as filed is to model PacifiCorp's actual NPC as accurately as possible. The adjustments filed by parties would decrease the accuracy of NPC and fail this threshold test.
- PacifiCorp's Market Cap Methodology as proposed is a simple and straightforward modeling adjustment that more accurately reflects the market depth that is available to the Company for market sales.
- Through the removal of the "must-run" setting, PacifiCorp is already modeling more economic cycling than is likely to occur in actual operations and reflecting those benefits in rates.
- CUB's proposal to run a GRID study closing [redacted] requires assumptions that are not based in actual operations and should not be adopted by the Commission.
- PacifiCorp recommends that the Commission reject Staff's changes to the "informational run" as such changes would assume away costs that are incurred in actual operations. These assumptions would essentially render the study meaningless.
- PacifiCorp's modeling of minimum take provisions in the TAM is appropriate and based in a reflection of actual operations that has been previously affirmed by

the Commission. Additionally, the modeling of the CSAs at DJ, Craig, Hunter, and Huntington should be found to be prudent.

- Sierra Club's arguments attempt to decrease coal generation by relying on inappropriate cost disallowances and highly unconventional dispatch practices that would increase costs for customers. The Commission should reject Sierra Club's recommendations.
- With regards to the other adjustments proposed by the parties, PacifiCorp recommends the Commission reject: (1) Staff adjustments regarding qualifying facility (QF) forecasting, (2) Staff's adjustment based on the Nodal Pricing Model (NPM), (3) Staff's Adjustment on Wheeling Costs, (4) AWEC's adjustment on other revenues, (5) AWEC's Adjustment on Bridger Coal Company (BCC) materials and supplies, and (6) CUB's proposal to change the 2023 TAM Filing Date.
- PacifiCorp accepts the following adjustments: (1) Staff's proposal to improve Energy Imbalance Market (EIM) Benefits Modeling, (2) Certain Staff Adjustments to the modeling of greenhouse gas (GHG) benefits, and (3) AWEC's adjustment to the production tax credit (PTC) rate.

III. REPLY UPDATE

Q. How has your NPC recommendation changed from the Initial Filing?

A. Total-company NPC has decreased by $6.5 million compared to the forecast included with the Initial Filing, from $1.445 billion to $1.439 billion. Exhibit PAC/401 shows that PacifiCorp's Reply Update proposes a rate increase of $1.7 million.

Q. Please explain the changes reflected in your revised NPC request.

A. First, consistent with the TAM Guidelines the Company made routine updates to the Initial Filing and updated the Company's proposed NPC with (1) the most recent official forward price curve (OFPC) and short-term firm transactions, (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts, and (3) EIM benefits based on most recent actual EIM benefit information as well as the updated OFPC. In addition, there was an update made to wheeling expenses to reflect the expected impact of the recently settled Bonneville Power Administration (BPA) rate case, and to incorporate the June 2020 through December 2020 actual activities. Finally, corrections to the market capacity limits, PTC benefits, and Other Revenue have been included in this update.

Additionally, the Company made three changes to the NPC in response to parties' testimony. The first is regarding the EIM benefit forecast. Staff testimony included a proposal to update the projection methodology for the PacifiCorp [redacted],[3] which has been accepted by the Company. The second is a set of proposed updates to the Company's GHG benefit forecast, which have been largely but not completely accepted by the Company. My testimony addresses this topic in greater detail below. Finally, as described later in this testimony, the Company is accepting AWEC's adjustment to the PTC rate.

Q. Please summarize the major changes in NPC resulting from the Reply Update.

A. Figure 1 below has details regarding the individual cost categories that accumulate to the change in the total NPC forecast.

[3] Staff/800, Dlouhy/19

Figure 1

Net Power Cost Reconciliation		
	($ millions)	**$/MWh**
OR TAM 2022 Direct	**$1,445**	**$23.87**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(69.8)	
Purchased Power Expense	44.8	
Coal Fuel Expense	8.5	
Natural Gas Fuel Expense	0.6	
Wheeling and Other Expense	9.5	
Total Increase/(Decrease) to NPC	**(6.5)**	
OR TAM 2022 Update	**$1,439**	**$23.76**

There is an increase in forecasted wholesale sales revenue of $69.8 million, the benefits of which are partially offset by an increase in purchased power expense of approximately $44.8 million. Coal fuel expense and natural gas fuel expense have increased by $8.5 million and $0.6 million, respectively. Finally, wheeling and other expenses have increased by $9.5 million.

Q. Please explain the updates included in the Company's Reply Update.

A. The Reply Update includes the following corrections and updates (the NPC impacts are based on the Initial Filing):

- **Market Cap Correction** – The Company corrected a miscalculation of the market caps that was included in the Initial Filing. The change was the inclusion of the January 2020 through June 2020 transaction history. The impact was an increase in total-company NPC of $28,500.
- **OFPC** – The Company updated the OFPC from December 31, 2020 to March 31, 2021. On average, market prices for electricity at the Mid-Columbia and Four

Corners markets increased by approximately 12 percent. Market prices for natural gas increased, on average, by approximately five percent. This update increased total-company NPC by $11.7 million.

- **Short-Term Firm Transactions** – Short-term sales and purchase transactions for electricity and natural gas were also updated through June 1, 2021. These updates increased total-company NPC by approximately $1.7 million.
- **QFs** – The Company has included QF updates through June 1, 2021. These updates decreased total-company NPC by approximately $1.2 million.
- **Coal Costs** – The Company has updated coal fuel costs to reflect changes in prices and volumes since the Initial Filing. Company witness Mr. Ralston provides additional detail on the update in his reply testimony. The update increases total-company NPC by approximately $5.8 million.
- **Wheeling –** The Company has updated wheeling expenses to reflect the actual costs from June 2020 through December 2020, and to incorporate the expected impacts of the recently settled BPA rate case. The update increases total-company NPC by approximately $9.5 million.
- **EIM Inter-Regional Transfer Benefits and GHG Benefits** – PacifiCorp's estimated EIM benefits for 2022 have been updated to include the most recent information through April 2020. On a total-company basis, the expected inter-regional transfer benefits are [redacted], an increase of [redacted]; the forecast GHG benefits are [redacted], an increase of [redacted]. This update decreased total-company NPC by approximately [redacted].

Q. Has PacifiCorp changed the allocation factor for EIM Benefits?

A. Yes, PacifiCorp has changed the EIM Benefits allocation factor from System Generation to System Energy. This results in a change of approximately [redacted] in EIM benefits allocated to Oregon.

Q. Why did PacifiCorp make this change?

A. PacifiCorp made this change as a result of the decision that was reached in the oral deliberations from PacifiCorp's Wyoming general rate case.[4] Failing to conform this change in all jurisdictions would result in the Company allocating more benefits than it expects to actually receive from EIM participation.

Q. Why is it appropriate to make this change in the TAM proceeding and not through the Multi-State Process?

A. EIM Benefits are a component of the TAM, and PacifiCorp and the parties in the TAM have always addressed the inclusion of these benefits for Oregon customers in this proceeding. Additionally, the allocation of EIM benefits is not directly addressed in the 2020 PacifiCorp Inter-Jurisdictional Allocation (2020 Protocol). While PacifiCorp pointed out to the Wyoming Public Service Commission that this a topic that should more appropriately be addressed in the Multi-State Process, PacifiCorp would propose that this change in the TAM be made in the interim.

IV. REPLY TESTIMONY – OVERVIEW AND GENERAL RESPONSE

Q. Please summarize Staff's proposed adjustments to the 2022 TAM.

A. In total, Staff proposes $15.31 million in adjustments to the Company's 2022 TAM on an Oregon-allocated basis. Staff's proposed adjustments include:

[4] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Service Rates*, Docket No. 20000-578-ER-20 (Record No. 15464), Deliberation Meeting on May 18, 2021.

- A [redacted] adjustment in total GHG benefits;[5]
- A [redacted] adjustment to wheeling costs;[6]
- A $1.53 million adjustment to QF power costs;[7]
- A [redacted] adjustment based on alleged "value lost" resulting from the Huntington minimum take contract;[8]
- A $5.1 million adjustment to the Company's average market cap methodology;[9]
- A $2.2 million adjustment to account for perceived benefits realized from the Company's upcoming switch to the NPM for the 2024 TAM;[10] and
- A $452,000 adjustment to the Company's [redacted].[11]

Q. Please summarize Sierra Club's adjustments to the 2022 TAM.

A. While Sierra Club does not quantify any specific adjustments, Sierra Club does recommend that the Commission reduce base costs for the BCC by [redacted] percent and modify costs related to the Company's Black Butte coal contract.[12]

Q. Please summarize CUB's proposed adjustment to the 2022 TAM.

A. CUB rejects PacifiCorp's proposed market cap methodology. CUB "recognizes that there has been an over-projection of market sales," however, and recommends "a

[5] Staff/100, Enright/39.
[6] Staff/300, Hanhan/5-6.
[7] Staff/500, Zarate/14.
[8] Staff/700, Anderson/22–23.
[9] Staff/800, Dlouhy/24.
[10] Staff/900, Gibbens/12.
[11] Staff/800, Dlouhy/23.
[12] Sierra Club/100, Burgess/59.

methodology that recognizes the changing nature of PacifiCorp's generation system while reducing the caps from their current level."[13]

Q. Summarize AWEC's proposed adjustments to the 2022 TAM.

A. In total, AWEC proposes $9.56 million in adjustments to the 2022 TAM. Specifically, AWEC proposes:

- A $2.6 million adjustment based on a projected increase in PTC benefits;[14]
- A $5.23 million adjustment to the Company's market cap methodology;[15]
- A $949,615 adjustment based primarily in increases to the Company's fly ash sales;[16] and
- A $785,644 adjustment to BCC cost estimations.[17]

Q. What does Calpine propose in the 2022 TAM?

A. Calpine disagrees with the Company's approach to calculating the Customer Opt-Out Charge. Additionally, Calpine proposes changing how renewable energy certificates are allocated to electric service suppliers

Q. Does SBUA provide any specific adjustments to NPC?

A. No. SBUA expresses some concerns about PacifiCorp's Schedule 23 rates based on the Company's ability to sell more power in the EIM but does not propose a specific adjustment.[18] Likewise, SBUA expresses concerns about the Company's average market cap methodology but proposes no specific adjustments.[19]

[13] CUB/100, Jenks/8.
[14] AWEC/100, Mullins/8.
[15] AWEC/100, Mullins/17.
[16] AWEC/100, Mullins/21.
[17] AWEC/100, Mullins/23.
[18] SBUA/100, Wentz/6.
[19] SBUA/100, Wentz/7.

Q. Please briefly describe the purpose of the TAM.

A. The purpose of the TAM is to capture costs associated with direct access and prevent unwarranted cost shifting between cost-of-service customers and customers that elect direct access service.[20] Significantly, the TAM also sets PacifiCorp's Oregon-allocated NPC for the upcoming year.[21] The Commission has articulated the importance of accurate NPC modeling in the TAM:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[22]

Q. Is a TAM filed separately from a general rate case, such as this case, limited in scope?

A. Yes. Stand-alone TAM proceedings are intended to be "narrower and more streamlined" than a TAM filed concurrently with a general rate case.[23] Generally, stand-alone TAMs are limited to specific issues related to (1) the prudence of Company contracts, (2) the appropriate modeling of contracts, and (3) "known and measurable changes to inputs for existing methodologies[.]"[24] PacifiCorp can also propose changes to its NPC modeling methodologies in its initial TAM filing, with

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[20] *In the matter of Pacific Power & Light Company (dba PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).
[21] *In the matter of PacifiCorp, dba Pacific Power 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 2 (Oct. 17, 2007).
[22] *In the matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016) [hereinafter 2017 TAM].
23 2009 TAM, Order No. 09-274, App'x A at 9.
24 Order No. 09-274 at 2.

accompanying support for the proposed changes.[25] Changes to the scope of a TAM proceeding are not addressed in a stand-alone TAM and should be advocated "in a future general rate case or other proceeding."[26]

Q. Please briefly describe PacifiCorp's Power Cost Adjustment Mechanism (PCAM).

A. Commission Order No. 12-493 approved a PCAM to allow PacifiCorp to recover or its customers to be credited for some of the difference between actual costs incurred to serve customers and the base costs established in PacifiCorp's annual TAM filing.[27] Each year the PCAM compares the NPC set in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is subject to an asymmetrical deadband between a $30 million under-collection and a $15 million over-collection, a symmetrical sharing band where the Company absorbs 10 percent of the variance outside the deadband, and finally a symmetrical earnings test where the collection or refund of a PCAM variance is limited to amounts that will bring PacifiCorp to within 100 basis points of the Company's authorized return on equity.[28] Additionally, the amortization of deferred amounts is capped at six percent of the revenue for the preceding calendar year.

Q. Has the current construct of the TAM and PCAM provided PacifiCorp with a reasonable opportunity to recover its prudently incurred NPC?

A. No. The PCAM only adjusts PacifiCorp's recovery for "unusual events and [to]

25 2010 TAM, Order No. 09-432 at 4.
26 2009 TAM, Order No. 09-274, App'x A at 9.
27 *In the matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 13-15 (Dec. 20, 2012).
28 *Id.* at 15.

capture power cost variances that exceed those considered normal business risk for the utility."[29] Because recovery adjustments will only occur if the Company experiences some unusual event or significant variance, PacifiCorp's rates have never been adjusted as the result of the PCAM despite the Company's under-recovery of NPC in 12 of the last 13 years. In nine of those years, the under-collection was greater than $15 million. The cumulative under-recovery is approximately $306 million. The full under-recovery for the past 13 years is shown in Figure 2 below.

Figure 2
Oregon NPC Collected in Rates versus Actual NPC[30]

Year	NPC Collected Through Rates	Actual NPC	Under Recovery of NPC
2008	$ 252,556,048	$ 286,401,464	$ 33,845,416
2009	248,429,624	261,335,991	12,906,367
2010	241,238,092	276,837,681	35,599,589
2011	301,662,279	333,544,839	31,882,559
2012	336,201,734	351,814,385	15,612,651
2013	348,474,235	382,126,867	33,652,632
2014	341,351,338	377,421,181	36,069,843
2015	343,993,011	362,384,220	18,391,209
2016	347,055,570	342,591,463	(4,464,107)
2017	340,640,219	342,861,000	2,220,781
2018	334,683,850	354,531,937	19,848,087
2019	340,850,405	382,928,436	42,078,030
2020	307,368,806	335,580,562	28,211,756

Q. To remedy the significant under recovery of NPC, did the Company propose any changes to the TAM and PCAM in its last rate case?

A. Yes. In PacifiCorp's last general rate case, docket UE 374 (2021 Rate Case),

[29] *Id.* at 13.

[30] Notably, the calculation of 2016 actual NPC shown here does not include certain coal costs that were excluded in the TAM. The exclusion of these costs from actual NPC shows small over-recovery of NPC in 2016. If these costs were included in actual NPC, it would show a small under-recovery in 2016.

PacifiCorp proposed several changes to the TAM and the PCAM. First, the Company proposed to replace the TAM and PCAM with a single annual power cost filing, the Annual Power Cost Adjustment (APCA).[31] Second, PacifiCorp proposed to remove deadbands, sharing bands, and earnings test from the PCAM.[32] By modifying the PCAM structure to make it more likely that rate changes would occur, the Company believed that stakeholder interest in the PCAM would increase and decrease the intensive Commission and stakeholder engagement in the TAM.[33]

Q. Did Staff, CUB, and AWEC support any of the proposed changes to the TAM and PCAM?

A. No. All three parties contended that PacifiCorp's TAM and PCAM framework was operating consistently with the policies the Commission applied to PacifiCorp in Order No. 12-493.[34] Accordingly, all three parties recommended that the Commission reject the Company's proposed changes.

Q. How did the Commission address PacifiCorp's APCA?

A. The Commission declined to adopt the APCA or the Company's proposed changes to the TAM.[35] Nonetheless, the Commission recognized that PacifiCorp could "make targeted forecast adjustments to remedy specific issues with its under-recovery" in its annual TAM filings.[36] For example, the Commission recognized that "PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a

[31] Docket No. UE 374, PAC/500, Wilding/9–10.
[32] Docket No. UE 374, PAC/500, Wilding/11.
[33] Docket No. UE 374, PAC/500, Wilding/12.
[34] Docket No. UE 374, AWEC/100, Mullins/37; Staff/1300, Gibbens/21; CUB/100, Jenks/44.
[35] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 129–30 (Dec. 18, 2020).
[36] Order No. 20-473 at 130.

'gross over-estimation of the sales benefit.'"[37] The Commission acknowledged that the Company could "improve its forecast accuracy with straightforward inputs or limits" in subsequent TAM filings.[38]

Q. Are the adjustments proposed by the parties in this case consistent with the purpose and scope of the TAM or the Commission's observations in Order No. 20-473?

A. No. As described above, the purpose of the TAM is to derive the most accurate forecast for setting fair, just and reasonable rates, which is especially important given the inadequate true-up mechanism in PacifiCorp's PCAM. However, as shown in Figure 2 above, PacifiCorp has systematically under-recovered its actual NPC based on understated TAM forecasts. In response, the Company continues to improve its modeling and pricing systems and search for additional adjustments so that forecasts better reflect the Company's actual operations.

Unfortunately, it appears that many of the parties' adjustments are not intended to improve the accuracy of the TAM forecast or support the Company's efforts to remedy specific issues with its historical NPC under-recovery. If adopted, the parties' adjustments would perpetuate and even increase PacifiCorp's chronic NPC under-recovery, recognizing that the high bar for triggering the PCAM will not be met. In addition, some of the parties now seem to be using the TAM to attempt to control PacifiCorp's actual operational and resource decisions, which is well outside the limited scope of the TAM.

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[37] Order No. 20-473 at 130 (quoting Docket No. UE 374, Staff/2400, Gibbens/19-22).
[38] Order No. 20-473 at 130.

Q. Please elaborate on your last point that some of the parties' adjustments move beyond accurately attempting to forecast NPC and seek to predetermine how PacifiCorp should operate its system.

A. CUB recommends that PacifiCorp economically cycle Jim Bridger Unit 1,[39] and Sierra Club proposes to track PacifiCorp's "daily unit commitment" and "dispatch decisions[.]"[40] These are just two of the recommendations that go beyond the purpose and scope of the TAM, and attempt to predetermine how PacifiCorp should operate its system to ensure that its customers receive safe and reliable service. PacifiCorp has an obligation to operate its system to meet its load obligations for customers in manner that is lowest cost and reliable. If PacifiCorp were to engage in some of the "operational" recommendations from parties, PacifiCorp's ability to provide safe and reliable service to customers would be seriously limited. These recommendations deviate from the purpose of the TAM which is to "update the forecast net power costs to account for changes in market conditions,"[41] and are outside the limited scope of the TAM, as defined by the TAM Guidelines.[42]

V. PROPOSED CHANGES TO GRID MODELING

A. Proposed Market Cap Redesign to Improve Accuracy of TAM Forecasting

Q. Has PacifiCorp proposed any new "straightforward inputs or limits" in this TAM proceeding as suggested by the Commission in Order No. 20-473?

A. Yes. PacifiCorp has proposed reverting to its original, pre-2013 TAM market cap methodology to increase the accuracy of its GRID NPC forecast. The GRID model

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[39] CUB/100, Jenks/17-18.
[40] Sierra Club/100, Burgess/3.
[41] 2009 TAM, Order No. 09-274, App'x A at 9.
42 *Id.* at 2, App'x A at 9.

assumes unlimited market depth for system balancing sales and purchases; it does not consider load requirements, transmission constraints, market illiquidity, or static assumptions about market prices that prevent PacifiCorp from making sales at the forecast price. To address this issue, the Commission has allowed PacifiCorp to place market caps on each individual marketplace. But, in the 2013 TAM, the Commission required the Company to base these market caps on the maximum monthly capacity during the most recent four-year period.[43] This market cap approach is commonly referred to as the "maximum of averages" approach. As a result, the ongoing level of sales in GRID is much higher than historical actual sales, undermining the accuracy of the NPC forecast. To remedy this problem, PacifiCorp proposes to revise the methodology, returning to an approach where market caps are based on the historical average of short-term firm, balancing and spot sales instead of the maximum of each month for the last four years. This "average of averages" approach better reflects system operations and improves the over-forecast of market sales.

Q. How has Staff addressed this proposed change?

A. Staff rejects the proposed change to market caps and recommends the continued use of the "maximum of averages" approach for an overall increase of off-system sales of $19.7 million company-wide or a decrease in NPC of $5.1 million Oregon-allocated.[44] Staff first points out that PacifiCorp made similar arguments about the over-forecasting of market caps in docket UE 245, the 2013 TAM, which the Commission rejected when it adopted the "maximum of averages" approach.[45] Even

[43] *In the Matter of PacifiCorp dba Pacific Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245 Order No. 12-409 at 7–8 (Oct. 29. 2012) [hereinafter 2013 TAM].
[44] Staff/800, Dlouhy/24.
[45] Staff/800, Dlouhy/30; Order No. 12-409 at 7-8.

though Staff acknowledges that the current “maximum of averages” approach may impose “unrealistic restriction[s]” it does not believe that the “average of averages” approach remedies the problem.[46] Staff also argues that once the Company switches to AURORA it will be able to account for some of these modeling errors since AURORA is a more sophisticated model.[47]

Q. Is Staff’s position contradictory with its position in PacifiCorp’s 2021 Rate Case?

A. Yes, in Order No. 20-473 in that docket, the Commission cited Staff’s testimony, stating that “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.’”[48] The Commission then specifically suggested that PacifiCorp “may be able to improve its forecast accuracy with straightforward inputs or limits.”[49]

Q. Is this a straightforward change as requested by the Commission in that order?

A. Yes, PacifiCorp’s proposed methodology is a straightforward limit that is being used in every other PacifiCorp jurisdiction and is directly designed to remedy the over-forecast in sales. The only difference is that, in the calculation of its market capacity inputs, PacifiCorp will use the average of the prior 48 months of trading activity as opposed to the maximum of the prior 48 months of trading activity.

[46] Staff/800, Dlouhy/29-30.
[47] Staff/800, Dlouhy/30–32.
[48] Order No. 20-473 at 130 (quoting Docket No. UE 374, Staff/2400, Gibbens/19-22).
[49] *Id.*

Q. Have any other parties made similar arguments opposing the Company's proposed change in market cap methodology?

A. Yes. AWEC has made many of the same arguments as Staff and recommends reducing NPC by $5.2 million on an Oregon-allocated basis.[50]

Q. How do you respond to Staff's and AWEC's claim that the Commission already adequately addressed this market cap issue in docket UE 245?

A. Staff ignores the substantial changes to PacifiCorp's generation resources and Commission policy since the Commission's determination in the 2013 TAM. First, as discussed above, the Commission has recognized the persistent under-recovery by PacifiCorp of NPC, particularly related to the over-estimation of off-system sales transactions.[51] This signals the need to reexamine the "maximum of averages" approach to find a solution that more accurately estimates sales transactions. Second, Staff does not acknowledge that the increased penetration of renewable resources in PacifiCorp's portfolio has increased the disparity between expected and actual off-system sales. The increasing gap between the GRID model's perfect foresight and the inherent intermittency and unpredictability of renewable resources has exacerbated the problem of overestimation of off-system sales.

Q. Staff and AWEC argue that PacifiCorp's change to the AURORA model will alleviate any market cap concerns.[52] What is your response to that statement?

A. Staff's and AWEC's arguments around AURORA are irrelevant to this TAM filing. The 2022 TAM uses the GRID model and therefore any potential modeling

[50] AWEC/100, Mullins/17.
[51] Order No. 20-473 at 130.
[52] Staff/800, Dlouhy/32; AWEC/100, Mullins/16–17.

differences between GRID and AURORA have no bearing on this proceeding. This proceeding sets rates for 2022 and, if Staff and AWEC see a potential remedy in a future proceeding, their recommendation should be saved for that future proceeding.

Q. Staff argues that AURORA adequately accounts for these limitations by modeling a "dynamic and volatile marketplace" that includes "uncertainty analysis" and "nodal pricing."[53] How do you respond to this statement?

A. Again, this statement is premature and speculative and should carry no weight in deciding the market cap issues in this case. Additionally, it is inappropriate to deny the Company the opportunity to recover prudently incurred NPC in 2022 because Staff believes a model that may be used in a future TAM case may produce a better forecast.

Q. Do you have concerns about Staff raising various arguments regarding the capabilities of AURORA versus GRID?

A. Yes, PacifiCorp has not yet filed a TAM with AURORA. PacifiCorp has deep concerns that parties may not fully understand the functionality of AURORA and are somehow viewing it as a panacea to solve a myriad of forecasting difficulties. AURORA represents a meaningful improvement to the Company's modeling capabilities, but it is not so robust as to produce valid results without a realistic set of constraints to reflect the normal conditions under which the Company operates. However, PacifiCorp remains committed to a thorough workshop process to provide Staff and the parties meaningful training and experience with AURORA.

[53] Staff/800, Dlouhy/32.

Q. Do you agree with AWEC's statement that PacifiCorp has conducted insufficient quantitative analysis to support average market caps?[54]

A. No. PacifiCorp is simply proposing to return to the market cap design it originally used to reflect real-world limitations on its ability to sell power into illiquid or less liquid markets hubs.[55] This original approach remains in place in all other states in which PacifiCorp operates. Since the Commission modified the Company's market caps in the 2013 TAM, the "maximum of averages" approach has forced the Company to choose the most extreme outlier value that can possibly be supported by the historical record in every case. That has manifested as an over-forecast of sales revenue and the result has been an under-recovery of costs in nearly every year since 2012.

Q. Is there a mathematical example that can show the shortcomings of the "maximum of averages" approach to calculating market capacity limits?

A. Yes, please see Figure 3 below for an example.[56] In this example, we see hypothetical average trading activity over the course of six time periods, spread across six different market locations. In each case, the average transacted volumes total 1,500 across the system on an aggregated basis. Because the market activity may be concentrated at different locations during each time period, the "maximum of averages" methodology grossly overestimates available liquidity, while the average of averages method captures it perfectly. This illustrates the pitfalls of intentionally choosing extreme

[54] AWEC/100, Mullins/11.
[55] *See, e.g.*, 2013 TAM, Order No. 12-409 at 7 (acknowledging that market caps "account [for] critical inputs" such as "market illiquidity"); *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 3 (highlighting the Company's argument that one reason for market caps is to prevent "artificially increasing sales to illiquid market hubs") [hereinafter 2016 TAM].
[56] This example is only intended to illustrate a methodological shortcoming and should not be taken to be based on the actual forecast values.

values and assuming they are representative of normal conditions, and further assuming that all of them will coincide across all locations in the future.

Figure 3

	Market Hub						
	Mid-Columbia	Palo Verde	COB	Four Corners	Mead	Mona	Total System Liquidity
Time Period 1	1,000	100	100	100	100	100	**1,500**
Time Period 2	100	1,000	100	100	100	100	**1,500**
Time Period 3	100	100	1,000	100	100	100	**1,500**
Time Period 4	100	100	100	1,000	100	100	**1,500**
Time Period 5	100	100	100	100	1,000	100	**1,500**
Time Period 6	100	100	100	100	100	1,000	**1,500**
Maximum of Averages Method	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**6,000**
Average of Averages Method	**250**	**250**	**250**	**250**	**250**	**250**	**1,500**

Q. Staff also claims that PacifiCorp neglected to account for GRID's over-forecasted purchases from market hubs when it cited Staff's analysis from the 2021 Rate Case.[57] Do you agree with this statement?

A. No. GRID does not presently include any purchase constraints. In any case, the magnitude of the variance compared to forecast is different between sales and purchases, with much higher variances for sales as shown in the Figure 4 below.[58]

Figure 3

	Short-Term Sales (MWh)			Short-Term Purchases (MWh)		
	Actual[1]	Forecast[2]	(Below)/Above Forecast	Actual[3]	Forecast[4]	(Below)/Above Forecast
2012	7,746,564	9,360,282	(1,613,719)	6,285,543	6,273,594	11,949
2013	7,867,127	11,529,969	(3,662,842)	4,213,141	6,413,790	(2,200,648)
2014	8,130,895	11,152,711	(3,021,816)	2,385,555	4,783,293	(2,397,739)
2015	7,619,541	11,420,069	(3,800,527)	4,686,590	4,938,847	(252,256)
2016	6,018,797	12,139,446	(6,120,649)	4,642,187	5,828,367	(1,186,180)
2017	6,651,663	13,806,284	(7,154,620)	6,408,925	7,134,540	(725,616)
2018	7,765,501	13,977,258	(6,211,757)	5,865,286	7,850,158	(1,984,872)
2019	4,947,298	15,623,544	(10,676,246)	5,433,773	9,503,672	(4,069,898)
2020	4,885,911	13,887,647	(9,001,736)	6,202,789	8,736,908	(2,534,119)

[1] *Adjusted Actual NPC (Total Short-Term Firm Sales + Secondary Sales)*
[2] *Final ORTAM Study by Year (Total Short-Term Firm Sales + Balancing Sales)*
[3] *Adjusted Actual NPC (Total Short-Term Firm Purchases + Secondary Purchases)*
[4] *Final ORTAM Study by Year (Total Short-Term Firm Purchases + Balancing Purchases)*

[57] Staff/800, Dlouhy/34.
[58] Please note, the source for this information is Oregon PCAM filing workpapers for each of the below listed years.

Q. Can you summarize Figure 4 above?

A. The table shows that in every year since 2012, the magnitude of the variance against forecast for sales has been larger than the magnitude of the variance against forecast for purchases. It also shows that, notwithstanding a noticeable increase in the magnitude of variance for both purchases and sales in 2019, the purchase variance has been holding steady while the sales variance grows ever more extreme.

Q. Given that the table above presents only volumes, can you offer a comparable analysis of revenues and expenses?

A. Yes, please see Figure 5 below.

Figure 4

	Short-Term Sales ($)			Short-Term Purchases ($)		
	Actual[1]	Forecast[2]	(Below)/Above Forecast	Actual[3]	Forecast[4]	(Below)/Above Forecast
2012	$ 184,814,023	$ 387,008,366	$ (202,194,343)	$ 95,575,429	$ 212,471,136	$ (116,895,708)
2013	222,455,456	399,101,906	(176,646,450)	161,006,194	198,219,908	(37,213,715)
2014	268,668,056	375,550,288	(106,882,233)	106,735,509	135,358,691	(28,623,181)
2015	211,282,682	402,556,300	(191,273,618)	153,619,101	155,034,108	(1,415,007)
2016	148,084,741	296,257,894	(148,173,153)	80,529,960	158,678,471	(78,148,511)
2017	189,651,228	375,076,473	(185,425,245)	138,560,262	186,311,560	(47,751,298)
2018	224,869,978	414,293,413	(189,423,435)	211,491,033	204,436,658	7,054,374
2019	168,712,218	475,838,322	(307,126,104)	202,338,950	243,108,270	(40,769,321)
2020	173,806,881	422,370,672	(248,563,792)	139,443,552	193,226,275	(53,782,723)

[1] *Adjusted Actual NPC (Total Short-Term Firm Sales + Secondary Sales)*
[2] *Final ORTAM Study by Year (Total Short-Term Firm Sales + Balancing Sales)*
[3] *Adjusted Actual NPC (Total Short-Term Firm Purchases + Secondary Purchases)*
[4] *Final ORTAM Study by Year (Total Short-Term Firm Purchases + Balancing Purchases)*

Q. Can you summarize Figure 5 as well?

A. Yes, it exhibits many of the same characteristics as the volumetric comparison table. In this case as well, the magnitude of the variance against forecast is larger for sales revenue than it is for purchase expense.

Q. Is this sort of comparative analysis meaningful in determining whether a forecast methodology is functioning as intended?

A. Yes. This analysis shows that the current methodology for forecasting sales activity is broken, unlike the forecast for purchase activity.

Q. Staff also conducted a market analysis between GRID-forecasted sales and actual sales from 2013 to 2020, concluding that "the Company's concerns of under-recovery are overstated."[59] Can you identify any problems with Staff analysis?

A. Yes. The information that Staff's testimony was based on came from the Company's response to Staff data requests 2 and 4. Those data requests specifically asked for total wholesale purchases and total wholesale sales. As a result, the volumes delivered were transacted volumes, not including adjustments for bookouts.[60] GRID has never accounted for the possibility of bookouts in modeling short-term sales.[61] Including booked out volumes in actual sales and purchases data will therefore prevent any apples-to-apples comparison to GRID's forecasted volumes for purchases and sales.

Q. Does Figure 5 in Staff's testimony accurately describe the Company's projected versus off-system sales?[62]

A. No, for the reasons cited above. GRID does not simulate offsetting purchases and sales at a single location in any hour, so booked out volumes do not belong in a discussion of the comparison between GRID's forecasted market activities and actual purchases and sales.

[59] Staff.800, Dlouhy/35–38.
[60] A "bookout" here refers to the closing of an open position prior to maturity. Bookouts are available when the Company holds offsetting positions (purchase and sale) for the same delivery point, in the same hour, with the same counterparty
[61] *See* 2013 TAM, Order No. 12-409 at 5 (discussing PacifiCorp's argument that a comparison of historical averages inclusive of bookouts against a GRID model exclusive of bookouts is like comparing "apples and oranges").
[62] Staff/800, Dlouhy/36.

Q. AWEC contends that any analysis of off-system sales between forecast NPC and actual sales can be difficult because much of the Company's off-system sales are "booked-out," or netted against offsetting purchases and not included in the actual NPC.[63] Do you agree?

A. I agree that the comparison can be difficult if booked-out volumes are included in the category of actuals. That is because, as explained above, the GRID model does not assume bookouts, so excluding those sales from NPC makes the volumes comparable and consistent with the volumes forecasted by GRID. In fact, these volumes support the change to average market caps. The PCAM data shown above is net of booked-out volumes and those show the Company's persistent under-recovery.

Q. AWEC also conducted an analysis comparing short-term firm sales volumes in the 2022 NPC forecast with the actual sales volumes from 2016 to 2020, including the Day-Ahead/Real-Time (DA/RT) adjustment and bookouts.[64] Using this analysis, AWEC shows a decrease in off-system sales based on the historical average. Do you agree with this analysis?

A. AWEC's analysis is based on flawed assumptions. Market caps are designed to simulate actual limitations on the Company's ability to sell to certain market hubs. As the Commission and Staff both observed in the 2021 Rate Case—and as CUB agrees in this case—GRID is currently forecasting an unrealistically high level of sales indicating that a more rigorous cap is required. AWEC's attempt to add the DA/RT adjustment and bookouts to the analysis does not negate this fact. Critically, market caps constrain GRID's behavior, not the DA/RT adjustment's behavior.

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[63] AWEC/100, Mullins/12.
[64] AWEC/100, Mullins/13–14.

Q. AWEC also argues that repowering projects and Energy Vision (EV) 2020 projects will increase sales volumes for 2022, justifying the current market cap methodology.[65] Do you agree?

A. No. The current 2022 TAM topology already accounts for repowering and EV 2020 projects to reflect the Company's new generation resources. Importantly, market caps do not exist to describe the composition of the Company's resource base, they exist to reflect the ability of the broader market to absorb the Company's excess power. The claim that if the Company has more resources, it is going to sell more power is incorrect. The "maximum of averages" model will still produce excessively high numbers for power sales that the Company will not be able to match. These new renewable resources provide value to PacifiCorp's customers through lower costs by providing zero-fuel cost energy which is used to serve load and displace fuel costs and market purchases, but they have not resulted in increased off-system sales. The Company's base NPC study with its proposed market caps and the study produced using the former market cap methodology both reflect the Company's ability to sell virtually all of its excess renewable energy.

Q. AWEC also argues that PacifiCorp's model validation analysis in the 2019 TAM proved that the GRID system "is able to produce the 2016 NPC within a very reasonable range compared to the actual 2016 NPC."[66] Can you extrapolate the data from the 2019 analysis to the current market?

A. The market analysis to which AWEC refers is inapplicable. While it is true that the GRID model predicted an accurate total NPC in 2016, Figure 2 above shows that for

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[65] AWEC/100, Mullins/15.
[66] AWEC/100, Mullins/15; Docket No. UE 339, PAC/100, Wilding/25.

every other year since 2013, GRID's forecast led to an under recovery of power costs. Further, the purpose of the 2019 study was not to analyze the effect of market caps on power sales but to provide a general validation of the entire GRID model for a Commission-mandated workshop.[67] PacifiCorp maintains that the GRID model is an accurate and reasonable power cost estimation modeling tool. The purpose of this market cap adjustment is not to completely overhaul the GRID model, but to adjust specific inputs to create a more accurate NPC model for the 2022 TAM.

Q. Finally, Staff believes that including off-market sales data from January 2020 to June 2020 would artificially deflate the Company's market cap under the "average of averages" approach because energy demand dropped sharply throughout this period.[68] Do you agree with this statement?

A. No. First, if one chooses to use a historical methodology, it is somewhat unusual to then pick and choose which portions of the history should be included. The solution is to include an amount of historical data sufficient to the task of diluting the impact of outlier values. Second, the Company updated the error in its market caps that was present in the direct filing study. The solution was specifically to include January 2020 through June 2020, and the total-company NPC impact was only $28,500.

[67] Docket No. UE 339, PAC/100, Wilding/15.
[68] Staff/800, Dlouhy/38–39.

Q. SBUA also raises concerns that the Company's "average of averages" approach will not "accurately reflect the economic conditions affecting Schedule 23 customers."[69] Do you believe that the Company's suggested approach will distort economic conditions for Schedule 23 customers?

A. No. As discussed above, this adjustment to markets caps simply tries to correct a modeling imbalance introduced into the GRID model in the 2013 TAM. The Commission and Staff have both acknowledged that the current "maximum of averages" approach to market caps distorts economic conditions and leads to under-recovery of NPC. Instead of distorting the economic reality, PacifiCorp's proposal creates a GRID model that more accurately reflects the sales the Company can make.

B. <u>CUB's Market Cap Proposal</u>

Q. How did CUB respond to the Company's market cap proposal?

A. CUB has two concerns with PacifiCorp's proposed changes. First, CUB believes that the approach proposed by the Company can result in inaccurate mathematical projections that will lead to unreasonably low power sales forecasts.[70] Second, CUB believes that changing the market cap methodology to project lower sales ignores the reality that PacifiCorp's available resources are changing.[71] Over the last four years, coal generation has [redacted], Company-owned wind resources [redacted], and long-term contracts for wind and solar [redacted].[72] Because the Company's new renewable power sources have a lower

[69] SBUA/100, Wentz/7.
[70] CUB/100, Jenks/4-5.
[71] CUB/100, Jenks/5-6.
[72] CUB/100, Jenks/6.

marginal cost, they should win a greater share of the market and lead to higher power sales.[73]

Q. Does CUB make any alternative proposals to modify the market cap methodology?

A. No, however, CUB does acknowledge that the current methodology has overestimated the actual short-term firm and balancing sales.[74] CUB declines at this time to propose an alternative methodology.

Q. How do you respond to CUB's claim that adding renewables should increase market sales?

A. The Company does not agree with CUB's claim, and in fact, as described above, market caps do not exist to describe the composition of the Company's resource base, they exist to reflect the appetite of the broader market for the Company's excess power.[75] As the Commission acknowledged in the 2013 and 2016 TAMs, market caps are necessary for GRID to capture actual market liquidity constraints in its sales forecast.[76] Further, any reasonable scenario where renewable resources are more productive than the GRID forecast wouldn't be limited to only the Company's resources. The presence of increasing amounts of low-priced energy from all owners on the system would tend to depress prices, making it more likely that the Company would reduce dispatchable generation, as opposed to selling into the market.

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[73] CUB/100, Jenks/6-7.
[74] CUB/100, Jenks/5.
75 *See* 2013 TAM, Order No. 12-409 at 7 (acknowledging PacifiCorp's argument that market caps account for critical inputs missing from the general GRID assumptions, including "load requirements, transmission constraints, and market illiquidity").

76 *See Id.* at 7–8; 2016 TAM, Order No. 15-394 at 4.

C. DA/RT Update

Q. Please describe the agreement on the DA/RT adjustment that the Commission approved in the 2021 TAM.

A. PacifiCorp incurs system balancing costs that are not reflected in the Company's forward price curve or modeled in GRID. To address this deficiency, in the 2016 TAM, the Company proposed the DA/RT adjustment to more accurately model system balancing transaction prices and volumes.

In the 2021 TAM, Staff proposed no adjustments to the DA/RT, but it did recommend a workshop regarding DA/RT and the transition to AURORA for NPC forecasts.[77] AWEC recommended a downward adjustment to the Company's NPC due to an overestimation of the DA/RT market cost.[78] The 2021 TAM was resolved by a stipulated settlement (2021 TAM Stipulation or Stipulation), in which PacifiCorp agreed to hold a workshop "on the transition from GRID to AURORA, how AURORA will capture the benefits of nodal pricing, and information on the DA/RT adjustment."[79]

Q. Has PacifiCorp held a workshop on DA/RT or AURORA?

A. Not yet. Due to the COVID-19 pandemic, the Company's transition to AURORA was delayed until the 2023 TAM, so it was premature to conduct a workshop.

Q. Does Staff continue to support the workshops addressing DA/RT and the transition to AURORA?

A. Yes. Staff recommends that the Company complete the workshop prior to the 2023

[77] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Power Mechanism*, Docket No. UE 375, Order No. 20-392 at 3 (Oct. 30, 2020) [hereinafter 2021 TAM].
[78] Docket No. UE 375, AWEC/100, Mullins/13–15.
[79] 2021 TAM, Order No. 20-392 at 3.

TAM filing. Staff also recommends a thorough review of the DA/RT adder and its continued usefulness once PacifiCorp shifts to the AURORA model.[80]

Q. Does PacifiCorp plan to hold these workshops before filing the 2023 TAM?

A. Yes. The Company plans to conduct workshops on the continued value of the DA/RT adder and its inclusion in the AURORA model. The Company also plans to conduct a workshop outlining the AURORA modeling process itself to promote understanding between Staff, Intervenors, and the Company about the modeling process ahead of the 2023 TAM.

VI. FORECASTING COAL GENERATION

A. Reply to Staff and CUB's Recommendations on Coal Unit Forecasting and Economic Shutdowns

Q. Please provide a general overview of Staff's testimony and recommendations to which you are responding.

A. Staff offers several specific recommendations related to economic cycling of coal units and two specific areas of concern related to coal fuel expenses. To respond, I first provide some background on PacifiCorp's process for the economic cycling of coal units in GRID now that the Company has removed the "must run" constraint. Then I discuss how PacifiCorp's modeling for 2022 coal costs included (1) an Initial Filing run with the "must run" setting turned off; (2) a counterfactual run with the "must run" setting turned on; and (3) an informational run with the "must run" setting turned off, no minimum take adjustments, and the average price of coal utilized.

[80] Staff/200, Cohen/5.

Finally, I address Staff's specific concerns and recommendations on economic cycling and coal fuel expenses.

1. Economic Cycling and Modeling of Coal Units

Q. Please provide background on modeling the economic cycling of coal plants.

A. In the 2018 TAM, Staff proposed an adjustment intended to model the economic cycling of coal plants, which had occurred in limited historical circumstances based on unusual market conditions in 2016 and 2017. The Commission rejected Staff's adjustment. In doing so, the Commission noted that it reviews "GRID dispatch issues to determine whether the Company is meeting its obligation to operate prudently, with prudent unit commitment and dispatch decisions that minimize costs."[81] The Commission then found that "PacifiCorp has explained that its current GRID modeling reflects historic, normalized practices regarding economic shutdowns of coal units."[82] Noting that PacifiCorp's operations may be responding to evolving market conditions, the Commission expressed an interest in understanding how PacifiCorp's operations may be changing.[83] To that end, the Commission directed PacifiCorp to hold a workshop to address economic cycling of coal plants and to make a presentation at a public meeting before the 2019 TAM on the workshop and specifically summarize any proposals identified to increase the accuracy of coal dispatch modeling due to economic outages, among other coal issues.

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[81] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Power Mechanism*, Docket No. UE 323, Order No. 17-444 at 11 (Nov. 1, 2017) [hereinafter 2018 TAM].
[82] *Id.*
[83] *Id.*

Q. Did the Company hold the workshop and provide the Commission a presentation on economic cycling of coal plants before the 2019 TAM?

A. Yes.

Q. Did the Company propose to model economic cycling of coal plants in the 2019 TAM?

A. Yes. In response to the Commission's interest and after workshops with Staff and other parties, PacifiCorp proposed modeling economic shutdowns for coal plants that are majority-owned by the Company, not participating in the EIM, and not under operational constraints that would preclude an economic shutdown in 2019. Staff agreed with this modeling approach and the Commission approved a stipulation that included PacifiCorp's proposal for modeling economic cycling of coal plants. In the 2019 TAM, Staff specifically testified that the "number of hours of economic cycling in PacifiCorp's forecast is consistent with PacifiCorp's historic cycling hours," which Staff testified "lends credibility to PacifiCorp's forecast, but raises additional concerns that PacifiCorp's actual cycling decisions may be less than optimal."[84] Staff continued: "PacifiCorp's actual cycling decisions are a PCAM issue, not a TAM issue, and parties should address PacifiCorp's actual operation cycling decisions in the next PCAM."[85]

Q. Did the Company include the economic coal plant dispatch modeling in the 2020 TAM?

A. Yes. The Company made no changes to the modeling that was agreed to and approved in the 2019 TAM settlement in the 2020 TAM. In the 2020 TAM, Staff

[84] Docket No. UE 339, Staff/200, Kaufman/8.
[85] *Id.*

disputed the Company's modeling, but again acknowledged that that the Company's method for modeling economic cycling produces more economic cycling hours than are realized in actual operation.[86] Staff ultimately entered into a stipulation that did not change the economic cycling modeling. The Commission approved the settlement.

Q. Did the Company's modeling of economic cycling change because of the 2021 TAM?

A. Yes. Prior to 2021, PacifiCorp included a "must run" setting for coal units in GRID to model coal units as base load operations. The "must run" setting allows coal units to reduce output to their minimum levels (which have decreased considerably in recent years, as discussed below) but did not allow the units to shutdown entirely, which is consistent with actual operations. Staff and Sierra Club recommended the removal of the "must run" setting. In the Stipulation, the Company agreed to remove the "must run" setting as part of its transition to AURORA. Even though the Company has delayed adopting AURORA until the 2023 TAM, the Company removed the "must run" setting from its 2022 Initial Filing to honor the spirit of the 2021 TAM Stipulation.

The 2021 TAM also addressed two related coal modeling issues: "minimum burn" constraints and incremental and supplemental coal costs. As part of the 2021 TAM Stipulation, PacifiCorp agreed to perform an "informational" run through its modeling system based on the Initial Filing but removing any operational constraints (such as "minimum take" provisions) and using an average coal price.[87] PacifiCorp

[86] Docket No. UE 356, Staff/300, Enright/20.
[87] 2021 TAM, Order No. 20-392 at 4.

has committed to providing Staff and intervenors this information run as part of its Initial Filing in the TAM each year until coal costs are removed from Oregon rates in 2029.[88]

2. The Economic Cycling Study

Q. What was Staff's reaction to the Economic Cycling Study?

A. Staff appreciated the work PacifiCorp put into the Economic Cycling Study and had two reactions to the information provided. First, Staff believes that the Economic Cycling Study's results are inadequate to conclude [redacted][89] Second, Staff questions why the Economic Cycling Study [redacted].[90] Staff hypothesizes that the drastic improvement in [redacted] was the result of assumptions PacifiCorp made in removing the "must run" setting in the 2022 TAM. If this is true, Staff believes that applying these assumptions could remedy the problems resulting from the removal of "must run" settings.[91]

Q. How do you respond to Staff's concern that the Economic Cycling Study is inadequate?

A. The Company is open to Staff's feedback and intends to be responsive. At this point, however, it makes sense to wait to do additional studies until after the 2023 TAM is filed using the AURORA model in place of GRID. If Staff's concerns persist after reviewing that filing, more detailed parameters can be settled upon and incorporated

[88] *Id.*
[89] Staff/700, Anderson/3.
[90] Staff/700, Anderson/4.
[91] Staff/700, Anderson/4.

into any future economic cycling studies. Through the removal of the must-run setting in the studies that accompany this filing, PacifiCorp is already ensuring that the potential economic benefits of cycling coal units are reflected in rates.

Q. How do you respond to Staff's questions regarding the volume of [redacted] in the base 2022 TAM study as opposed to the Economic Cycling Study?

A. As PacifiCorp discussed in its Initial Filing, adjustments had to be made to ensure that the model results were rational and consistent with prudent utility practice and feasible operations. These adjustments included [redacted]. Because [redacted], the Company modified the multiplier on [redacted] in order to [redacted] in the 2022 TAM base study. Thus, the decrease in [redacted] does not signify that the resource constraints associated with removal of the "must run" setting have dissipated.

3. CUB's Recommendations Regarding the Economic Cycling Study

Q. As a result of the Economic Cycling Study, has CUB's position changed on any issues related to coal cycling?

A. Yes. CUB believes that the Economic Cycling Study "raises real doubts about the [redacted]"[92] CUB believes that [redacted]

[92] CUB/100, Jenks/16.

[redacted].

Q. Does CUB make a recommendation regarding cycling?

A. Yes. Because PacifiCorp's most recent integrated resource plan (IRP) found an [redacted],[93] and the Economic Cycling Study [redacted], CUB would like the Company to conduct a GRID study [redacted].[94] Second, CUB recommends that PacifiCorp [redacted][95]

Q. CUB had "trouble understanding how [redacted].[96] Please respond.

A. CUB seems to confuse the Company's IRP modeling with the TAM modeling. The TAM is fundamentally different from the IRP in its input assumptions and its goal. The TAM is an attempt to forecast NPC on a normalized basis for the purpose of setting rates for the next calendar year. The IRP is a long-term resource planning study that views the system topology and the Company's resource composition as subject to change. It uses a different model, includes different inputs, and achieves an entirely different goal. Studies like the IRP that incorporate new resources and topology changes—and contemplate a different timeframe—may reach different

[93] Docket No. LC 70, Vol. II, App'x R.
[94] CUB/100, Jenks/16.
[95] CUB/100, Jenks/15-16.
[96] CUB/100, Jenks/16.

conclusions from that of a short-term power cost forecast like the TAM. For example, the IRP may assume resource additions in 2023-2024, before or concurrent with the [redacted], while the TAM is a one-year forecast based on existing resources only.

Q. Would customers have benefited from [redacted]e [redacted]?

A. No. First, many parts of the western united states are currently experiencing drought conditions, causing hydro conditions to be historically bad. The spring runoff was particularly low in the region because of the lack of precipitation. The snowmelt also suffered because of dry conditions. These conditions among others led to strong electric market prices in both the northwest and southwest during much of the quarter and customers benefits from the lower priced generation from [redacted]. On June 16, 2021, electric prices in the southwest were above $1,400/megawatt-hour (MWh) and on June 25, 2021, electric prices in the northwest were approximately $330/MWh. If [redacted] before these events the Company would have obviously committed this unit to come back online. However, there is a greater risk of a forced outage during a cold start as opposed to ramping the unit up from its minimum operating level.

Q. Are there other reasons that make taking [redacted] for an [redacted] impractical?

A. Yes. First, [redacted] is joint owned with [redacted] and removing the plant from service would have to be agreed to with [redacted]. It is important to note that [redacted] will have different needs. Additionally, because of [redacted]. If a unit is offline for economics, that limits the utility's ability to perform maintenance on other units.

Q. Do you agree with CUB's proposal to run a GRID study closing [redacted]?

A. No. First, any study conducted now will be too old to be relevant when conducting [redacted]. As discussed above, [redacted], especially during drought conditions when hydro reserves are low. Second, the TAM is not designed to dictate actual operations. Instead, the purpose of this docket is to ensure accurate projections of NPC for the coming year. Conducting a study focused on actual operations, not forecasted NPC, is outside the scope of this docket. Finally, [redacted], especially in years with strong hydro generation. Conducting a study that would only affect a small proportion of time is not a good use of resources.

4. Results of the Informational Run

Q. At a high level, what is the informational run?

A. As part of the 2021 TAM Stipulation, PacifiCorp agreed to perform an "informational run" of the Company's GRID model that removed any operational constraints related to minimum take provisions in the CSAs and used an average coal price for purposes of dispatching coal plants.[97]

Q. What were the results of the informational model run?

A. The informational run resulted in a decrease in coal fuel expenses of [redacted] from [redacted] to [redacted], while NPC increased by [redacted] from [redacted] to [redacted].

Q. How do you explain the increase in NPC even though coal fuel expenses fell?

A. While the informational run does not include any minimum take provisions, it does adjust the average cost to compensate based on take or pay contracts with coal suppliers.[98] Furthermore, the costs of other resources that replace the coal fuel expense are also included in the model.

Q. Does Staff believe that the take or pay adjustments are appropriate in the informational model run?

A. No. While Staff admits that minimum take costs associated with take or pay contracts are valid when incurred under a prudent contract, Staff believes that these costs obscure the effects of economic cycling for the purposes of the informational run.[99]

Q. Does Staff propose any changes to the informational run as a result?

A. Yes. Staff proposes changing the definition of informational run to a:

> model run that removes any operational constraints **and costs** related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants.[100]

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[97] 2021 TAM, Order No. 20-392 at 4.
[98] Staff/602, Fox/14-15.
[99] Staff/600, Fox/9.
[100] Staff/600, Fox/10 (emphasis in original).

Q. Do you agree with this change to the informational run?

A. No, such an approach would render the study meaningless. The Commission has previously acknowledged the need to model minimum take provisions "to achieve the overall least-cost dispatch of the entire coal fleet while meeting minimum-take obligations for each plant" in previous TAMs.[101] Further, assuming away costs that would actually be incurred simply invalidates the study results. The study would no longer be reflective of the NPC that would be incurred by the Company if such a dispatch plan were to be pursued in the Company's actual operations.

5. Coal Costs & Burn Rate

Q. After conducting the 2022 TAM initial run, the counterfactual run, and the informational run, what is your general conclusion regarding coal costs?

A. After conducting the three GRID studies, NPC fell very slightly in the counterfactual study when compared to the 2022 TAM, showing that the economic benefits of coal cycling are *de minimis* for the 2022 test period.

Q. Does Staff agree with your conclusions?

A. Largely, yes. Staff agrees with the Company's coal cost calculations but recognizes that there are large variances associated with a few individual plants. Staff also believes that many of the other variances result from changes in individual plant burn rates.[102]

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[101] *See* 2017 TAM, Order No. 16-482 at 10–11 (accepting the Company's modeling of minimum take provisions in the 2017 TAM).
[102] Staff/600, Fox/10-11.

Q. Does Staff question the veracity or prudence of any burn rates or coal costs in particular?

A. Yes. Staff notes that the burn rate at Naughton has markedly increased and questions the commitment to increase the contracted supply at the Dave Johnson Plant when PacifiCorp acknowledges a highly competitive supply market with numerous supply options.[103]

Q. Can you explain either of these variances?

A. Yes. While the reply testimony of Mr. Ralston will focus on the prudence of PacifiCorp's Dave Johnson supply contracts, I will address the increased burn rate for the Naughton plant.

Q. Please explain.

A. Naughton Unit 1 has an expected overhaul scheduled for 2022. However, Naughton Unit 1 is scheduled for retirement in December 2025 and next year's maintenance will be its final overhaul.[104] As a result, PacifiCorp expects the overhaul to have less of an efficiency recovery when compared to a more routine overhaul. In addition, the entire facility is expected to operate at lower capacity, resulting in a significant change in burn rates for the entire plant. The heat rate inputs in GRID describe a curve, not a fixed value, and dispatchable units (both coal-fired and gas-fired) are generally less economic at lower output levels. Operating at a lower average output level will lower overall plant efficiency and increase operating costs.

[103] Staff/600, Fox/5.
[104] Staff/602, Fox/5-6.

6. Fuel Security and Minimum Take Provisions

Q. Does Staff recommend any NPC adjustments related to the Company's minimum take coal contracts?

A. Yes. After reviewing the Company's 2022 TAM and the counterfactual study, Staff believes that Huntington's minimum take contract is "not calibrated appropriately for the economic realities" of today.[105] Accordingly, Staff recommends removing the minimum take requirement at Huntington in future TAM proceedings to remove minimum take costs from future NPC calculations.[106] Alternatively, if PacifiCorp develops a "robust forecasting methodology" for accounting for minimum take provisions in CSAs, it may be able to account for some of the costs of the Huntington Contract in future TAM proceedings.[107]

Q. What is the result of Staff's adjustment?

A. Staff proposes to remove [redacted] from NPC.[108]

Q. Is it reasonable for the Commission to alter the modeling of the Huntington contract years after it has been included in rates?

A. No. Mr. Ralston's reply testimony details the history and prudence of the Huntington minimum take contract. Nonetheless, I understand that PacifiCorp entered the current CSA after it retired the Deer Creek mine in 2015, resulting in a reduction of rates for Oregon customers. In its order approving the closure of the Deer Creek mine, the Commission found the transaction produced substantial benefits for customers and

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105 Staff/700, Anderson/21.
106 Staff/700, Anderson/22.
107 Staff/700, Anderson/22.
108 Staff/700, Anderson/22–23

was in the public interest.[109] The Commission has included costs incurred under the Huntington CSA in each TAM since the Deer Creek mine closure. The Commission examined the agreement's minimum take provision in the 2017 TAM and found the agreement was prudent.[110]

Q. Staff also claims that PacifiCorp must provide more robust modeling for the minimum take levels for Dave Johnston's and Craig's coal supply contracts to include these costs in future TAM proceedings.[111] Should the Company be disallowed from modeling these minimum take contracts in future TAMs?

A. No. Staff seems to believe that if, at any point over the life of the agreement, the proper modeling of a coal contract requires an iterative process in GRID to reflect the optimal dispatch forecast, it renders the agreement imprudent on the basis that the Company was insufficiently prescient regarding future market conditions when it executed the agreement. Staff simultaneously holds that, if a new contract *does not* require the iterative process to be performed, it *still* should not be found prudent, and should remain subject to further lookback reviews. This is inconsistent with my understanding of prudence, which examines the "objective reasonableness of a decision at the time the decision was made."[112]

Q. Outside of the Huntington minimum take contract, does Staff propose any more adjustments resulting from minimum take contracts?

A. No. However, Staff does question whether iterative modeling is necessary to meet

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[109] *In the Matter of PacifiCorp dba Pacific Power, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 at 4 (May 27, 2015).
[110] 2017 TAM, Order No. 16-482 at 9.
[111] Staff/700, Anderson/17.
[112] *In the Matter of the Application of PacifiCorp for an Accounting Order Regarding Excess Net Power Costs*, Docket Nos. UM 995, UE 121, & UC 578, Order No. 02-469 at 4 (July 18, 2002).

Wyodak's minimum take contract based on [redacted] gap between the TAM's predicted fuel burned and the contract minimum.[113] Staff notes that adjusting Wyodak's output to the minimum take would reduce 2022 power costs by [redacted] assuming Wyodak would displace generation at the average cost for all resources.[114]

Q. Why does the 2022 TAM hold Wyodak's output at [redacted] below the contract minimum?

A. Mr. Ralston's reply testimony describes the specific circumstances around Wyodak, [redacted]. Further, the cost of the generation being displaced would be for a specific unit over a specific timeframe, and not an average cost of generation. If NPC could be reduced by running Wyodak at higher outputs levels, the GRID model would be running Wyodak at higher output levels already.

B. <u>PacifiCorp's Reply to Sierra Club</u>

Q. Please provide a general overview of Sierra Club's testimony and recommendations.

A. Sierra Club offers several specific recommendations for adjusting the 2022 TAM NPC forecast and several broader recommendations for future changes to NPC modeling, each of which is discussed in detail below. Specifically, Sierra Club recommends that:

- The Commission to direct PacifiCorp to revise its NPC for the 2022 TAM for Jim Bridger fuel costs which it claims are the result of incorrect

[113] Staff/600, Fox/31.
[114] Staff/600, Fox/31.

assumptions about the marginal cost in GRID and a lack of consideration for fuel source flexibility;

- The Commission should ensure that NPC projections reflect the true incremental costs of fuel, especially when there is no pre-existing minimum take or approved contract, and to remove other "distortions" from PacifiCorp's modeling in future TAM proceedings;
- The Commission should only approve 2022 TAM rates on an interim basis for all projected costs associated with PacifiCorp's open fuel supplies at Jim Bridger, Naughton, and Dave Johnson. PacifiCorp should provide these contract details in a supplemental filing, including additional GRID runs. Once the Commission has reviewed the specifics of each contract, it should adjust rates accordingly;
- The Commission should also defer any final approval of any fixed costs for BCC coal included in the 2022 TAM until the Commission conducts a prudence review of these costs;
- The Commission should require the Company to provide a tracking report detailing its daily unit commitment and dispatch decisions for each of its thermal plants throughout 2022;
- The Commission should require PacifiCorp to include a report on the steps the Company has taken to reduce BCC mine costs and replace this resource with lower cost sources in future TAM proceedings;
- The Commission should require PacifiCorp to provide copies of its CSAs and affiliate mine contracts in all future TAM proceedings; and

- The Commission should conduct a comparison of each cost recovery mechanism to ensure there are no duplicative depreciation costs for the BCC mine in both base rates and TAM proceedings.

Sierra Club makes further arguments that will be addressed in the reply testimony of Mr. Ralston.

Q. Generally, how do you respond to Sierra Club's recommendations?

A. Sierra Club's arguments largely rely on false comparisons, overly simplistic analyses, and a disregard of established economic principles. To decrease coal generation, Sierra Club recommends both cost disallowances and highly unconventional dispatch practices that would increase costs for customers. Through its IRP, PacifiCorp is accomplishing the same objective—a reduction of emissions—in a methodical and cost-effective manner that reduces NPC for customers. Further, many of the additional filing requirements outlined in Sierra Club's testimony are outside the scope of the TAM proceeding and are more appropriate to discussion in the Company's IRP proceedings. Sierra Club's recommendations should be rejected as both unnecessary and harmful to customers.

Q. Sierra Club generally argues that the 2022 TAM may be the first year where the Company under-recovers outside of the PCAM deadband because the Company removed "must run" constraints from the GRID.[115] Do you agree?

A. No. To the extent that there is any risk of an under-recovery falling outside the deadbands, I do not believe this possibility is related to the removal of "must run" settings. Sierra Club equates the entire $114 million reduction in fuel expense to

[115] Sierra Club/100, Burgess/9.

cycling coal units. However, the proposed change in market caps in the 2022 TAM provides a more plausible driver to reduced coal generation. When the GRID model has higher market caps, it sees more power available for sale and tries to run dispatchable resources to meet the perceived market demand. In addition, simple changes in power market prices and several hundred thousand additional MWh of wind generation will also alter the way that the Company's dispatchable resources are forecasted in GRID.

Q. Sierra Club contends that PacifiCorp is dispatching coal even when it is not economic. Has PacifiCorp's coal generation declined steeply in recent years, reflecting the changing economics of its resource stack?

A. Yes. The facts undermine the basic premise of Sierra Club's testimony. Since 2012, PacifiCorp's overall coal generation has decreased by 19 percent. In particular, coal generation at the Jim Bridger plant has decreased by 13 percent, and coal generation at the Naughton plant has decreased by 43 percent (reflecting the conversion of Naughton Unit 3 to a natural gas unit in 2019).

Furthermore, in PacifiCorp's 2013 IRP, only 1.5 percent of PacifiCorp's resource capacity came from renewable resources.[116] In contrast, the 2019 IRP projects 33 percent of PacifiCorp's resource capacity in 2021 to come from renewable resources.[117] Similarly, PacifiCorp's coal-fired generation, as projected by the IRP, will drop from 53 percent to 31 percent of its resource capacity mix during this same timeframe.[118]

[116] PacifiCorp's 2013 Integrated Resource Plan at 229 (Apr. 30, 2013).
[117] PacifiCorp's 2019 Integrated Resource Plan at 257 (Oct. 18, 2019).
[118] *Id.*

1. Overview of Coal Contract Modeling in GRID

Q. Please define the incremental cost of production.

A. The incremental cost of production is the cost required to increase the production of a generation unit by one MWh. For example, if a generation unit is online and producing 100 MWh of energy and the cost to increase production to 101 MWh of energy is $15, then the incremental cost of production is $15 per MWh. This cost of $15 per MWh primarily consists of fuel costs.

Q. Please define the average cost of production.

A. The average cost of production is the ratio of the total cost of production to the total energy produced. For example, if a generation unit serves 1,000 MWh of retail load and incurs startup costs, fuel costs, operations costs and maintenance costs totaling $60,000, then the average cost of production is $60 per MWh.

Q. How does GRID model the dispatch of PacifiCorp's generation resources?

A. GRID dispatches individual resources such as coal plants on a marginal or incremental cost basis, to optimize the dispatch of the Company's existing system in the most economic, or least-cost, manner while accounting for constraints. If the cost to generate is less than the market price of electricity, the plant is dispatched up. Once the total generation from each plant is known, the total cost of the fuel (including any fixed charges) is spread over the total fuel volume.

Q. Please explain how PacifiCorp models coal fuel costs for the purpose of its NPC forecast and short-run optimization.

A. To accurately forecast coal generation costs, the Company models its coal plants to simulate the actual dispatch. The Company excludes from its dispatch commitment analysis the cost of coal that is subject to take-or-pay provisions.

Q. What are take-or-pay provisions?

A. As explained in greater detail by Mr. Ralston, take-or-pay provisions provide for a minimum payment to be due if PacifiCorp fails to take the minimum contract volume. The Company pays for the full purchase price of fuel due if the annual purchases are below the minimum volume required for a certain timeframe such as a contract year.

Q. How are take-or-pay provisions modeled in GRID?

A. The incremental fuel cost input to GRID consists of only a single value, so multiple pricing tiers are not recognized by the model. For that reason, in a short-term forecast, such as the TAM, the Company uses an iterative process to arrive at a marginal fuel cost that produces a result where the generation at each plant meets the minimum purchase obligations present in the coal supply and transportation agreements. This modeling approach is consistent with previous TAM proceedings.[119]

Q. What are liquidated damages provisions and how are they modeled in GRID?

A. As explained in greater detail by Mr. Ralston, liquidated damages provisions provide for a payment, less than the full price of coal, to be due if PacifiCorp fails to take the minimum contract volume. The Company accounts for liquidated damages in its dispatch analysis by recognizing that these costs will be incurred if the units are not dispatched at contractual minimums. The Commission has previously approved this modeling approach for specific liquidated damages provisions.[120]

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[119] *See* 2017 TAM, Order No. 16-482 at 11 (finding that the modeling of minimum take provisions "is consistent with past TAM proceedings").
[120] *See* 2018 TAM, Order No. 17-444 at 12 (approving the Company's modeling approach for Cholla's liquidated damages provision).

Q. Does Sierra Club have concerns about how the coal costs are calculated for use in the GRID model?

A. Yes. Sierra Club believes that some of the inputs in the GRID model may be leading to excessive dispatch of coal at some plants based on the inputs the Company uses in the GRID model.[121] Sierra Club is also concerned that the Company may be dispatching coal resources during actual operations based on the same inputs. Finally, it believes excess dispatch may affect the Company's approach to coal contract negotiations because of inaccurate assumptions in the GRID model.[122]

Q. Does Sierra Club suggest resource replacements that could reduce coal generation?

A. Sierra Club suggests that building a 1,400 MW wind project might be able to displace as much as 50 percent of Bridger's output.[123] Putting aside reliability issues, the average price of all 10 wind resources in the 2019 TAM was [redacted]. Bridger's cost of generation was [redacted], meaning that this approach would increase costs for customers.

Q. Do you agree with Sierra Club that the use of the dispatch tier is not the ideal way to model PacifiCorp's fuel costs because it accounts for minimum take contracts?[124]

A. No. Incremental cost dispatch is ultimately a lower cost approach for customers. The Company does not use an average price as a dispatch price in short-term forecasts such as the TAM because the cost of coal in a take-or-pay volume tier is not

[121] Sierra Club/100, Burgess/19–20.
[122] Sierra Club/100, Burgess/19–20.
[123] Sierra Club/100, Burgess/18.
[124] Sierra Club/100, Burgess/29–30.

avoidable. The cost in that minimum take volume tier is a previously incurred or sunk cost, as the cost for that volume is going to be incurred regardless of whether the coal is consumed. The take-or-pay provisions in PacifiCorp's CSAs require the payment for the coal even if it is not delivered or used for generation, so the fuel portion of the marginal cost of generation in that price tier is zero. Because those take-or-pay provisions result in actual fuel costs, the effect of decrementing coal generation to those levels and replacing that power with market purchases or other generation would be to increase NPC by the value of the replacement power.

Q. Can you provide a simple example that illustrates why marginal costs are more appropriate to consider than average costs when making a near-term economic decision?

A. Certainly. Consider the decision to make a trip to the store. To make that trip, you could either take your car, or you could rent an identical car. If you calculate the cost per mile including fixed expenses like the monthly car payment, you might think that renting a car is economically sound, since the charge you would incur for a single day's use would (presumably) be less than your monthly payment. If you consider only the incremental cost of the decision, correctly recognizing that your responsibility to make the monthly installment payment on your car has nothing to do with whether or not you go grocery shopping, you reach the obvious conclusion that you should simply use the car you already own since doing so would not incur an additional rental charge. This illustrates why Sierra Club's recommendation runs counter to basic economic principles.

Q. After comparing the GRID dispatch tier to the cost tier, Sierra Club claims that some of PacifiCorp's coal plants have dispatch tier costs that are significantly lower than costing tiers.[125] How do you respond?

A. Any firm with fixed costs will exhibit those same production cost characteristics. The dispatch tier costs are the estimation of the incremental costs to operate PacifiCorp's coal plants. The purpose of using the incremental generation cost for dispatch is to minimize the total cost of electricity supply, including plant generation and off-system power purchases and sales.

For example, at the Jim Bridger plant, the dispatch tier cost represents the incremental cost associated with procuring additional coal above the minimum mine plan volumes. For the Jim Bridger plant, the incremental cost is derived by evaluating production and cost differentials between two operating plans at BCC. While BCC is an affiliate captive mining operation adjacent to the plant and can adjust coal production quantities to comply with reasonable changes in fuel requirements at the plant over time, most base costs within the year of the mine plan are fixed and unavoidable.

Q. Please explain the Company's approach to calculating incremental costs at plants with minimum fuel purchase requirements.

A. The incremental fuel cost input to GRID consists of only a single value, because multiple pricing tiers are not recognized by the model. For that reason, the Company uses an iterative process to arrive at a marginal fuel cost that produces a result where the generation at each plant meets the minimum coal purchase requirements, i.e., the

[125] Sierra Club/100, Burgess/25–26.

contractual minimum take provisions, present in the supply contracts. The point is to ensure that customers receive all the energy associated with the costs charged under the supply agreements. GRID cannot accommodate a contractual minimum-take provision, so this is the mechanism employed to ensure those contractual provisions are accurately modeled. The approach taken in GRID correctly recognizes that minimum take provisions impose costs that the Company incurs regardless of whether the minimum volumes are burned. As a previously incurred cost that cannot be avoided, it makes economic sense to ensure that at least these volumes are consumed because they have an effective incremental price of zero. It is worth noting that this approach will not be utilized in AURORA in future TAMs, as individual price tiers and volume constraints are supported by that model.

Q. Has the Commission examined this process in the past?

A. Yes, in the 2017 TAM, the Commission examined PacifiCorp's process to calculate the incremental fuel costs in the GRID model to ensure the minimum-take provisions of the coal contracts are met and customers received the generation associated with the fuel already procured. The Commission accepted this as a normal and appropriate part of modeling the TAM and was consistent with past TAM proceedings.[126]

Q. What does Sierra Club believe that the Commission should consider when evaluating the prudency of the Company's fuel costs?

A. Sierra Club asserts that the Commission's evaluation of NPC should consider the prudency of the Company's fuel costs not only on a short-run marginal cost basis, but also on a long-run marginal costs basis. It claims that the Commission should focus

[126] 2017 TAM, Order No. 16-482 at 10-11.

its evaluation on: "a) existing fuel supplies with no minimum take penalties, b) open positions where future fuel supplies are expected but contracts have not yet been executed, c) recently executed fuel supplies that have not been evaluated or approved in prior TAM proceedings (including those with a minimum take obligations), and d) existing fuel supplies that do have a minimum take obligation but could be readily revised."[127]

Q. Based on this "evaluation," what does Sierra Club recommend?

A. Citing the costs in the Company's 2021 NPC projections related to CSAs for the Craig, Dave Johnston, Hunter, Naughton, Jim Bridger, and Wyodak plants, Sierra Club recommends that PacifiCorp estimate generation assuming the full cost associated with the costing tier (average cost), rather than the dispatch tier.[128] Sierra Club claims that:

> If the generation quantity using the costing tier price was less than what the minimum take provisions requires, then executing the contract would not have been prudent under the terms PacifiCorp negotiated. . . . If GRID showed that the minimum take provision for a new contract was not met, the correct solution is not to tinker with the inputs . . . this result simply reflects that the contract was entered imprudently and the Company should be responsible for any shortfall payments that occur, not its customers.[129]

Q. Does Sierra Club make a specific proposal applying this new "evaluation" process?

A. Yes. Sierra Club recommends that PacifiCorp revise its NPC forecasting for the Jim Bridger plant to represent the "true" marginal cost as outlined by Sierra Club.[130]

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[127] Sierra Club/100, Burgess/29–30.
[128] Sierra Club/100, Burgess/31–32.
[129] Sierra Club/100, Burgess/33.
[130] Sierra Club/100, Burgess/34.

Q. Why would it be inappropriate to forecast NPC without accounting for the impact of the minimum-take provisions of certain contracts?

A. It is unreasonable to simply ignore these very real costs, based solely on Sierra Club's supposition that when GRID shows that a minimum take provision is not met, it must be a result of an imprudent coal supply agreement. As noted above, the definition of prudence is not so expansive that it requires the Company to be prescient regarding future events. The exact same logic Sierra Club relies upon could be used to disallow cost recovery related to a fixed price power purchase agreement (PPA) with a wind farm. A more accurate, reasonable, and functionally enforceable definition of prudence requires only that the contract be reasonably calibrated to minimize costs and risk based on factors reasonably known at the time of execution.[131] Sierra Club has not introduced any evidence demonstrating that the Company's contracts fail this standard.

Mr. Ralston's reply testimony discusses minimum contract requirements and demonstrates the prudence of the Company's approach to managing its coal plant and mine operations. I will discuss the issues related to Sierra Club's analysis of Jim Bridger in a separate section below.

Q. Sierra Club asserts that the Company has performed no formal analysis of the "costs and benefits of economic cycling prior to making unit commitment or dispatch decisions."[132] Why is such an analysis unnecessary?

A. Economic cycling is when a utility takes a coal plant offline to avoid fuel costs and

[131] *See* Order No. 20-473 at 35 ("[The Commission] must determine whether [PacifiCorp's] actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.").
[132] Sierra Club/100, Burgess/22.

replaces that generation with other resources. Thus, when a unit is taken offline for economic purposes, the savings that a utility, and ultimately its customers, realizes is avoided fuel costs. For PacifiCorp, such an analysis of the cost and benefits of economic cycling is unnecessary because the minimum operating levels of the its coal plant units have been reduced significantly, in some cases 50 megawatts (MW) or below. The result is avoided fuel costs are less. Therefore, to make economic cycling worthwhile, a coal unit has to be held offline for a longer period of time in order to overcome other costs, such as start-up costs. Holding a unit offline for a longer period of time introduces new risks, including subjecting the Company and its customers to price spikes for replacement energy and reliability. Bringing a coal unit back online is not akin to flipping a light switch on and off, instead it takes a longer period of time and there is risk in turning a plant on and off.

Q. Can you provide an example?

A. Yes. Consider an example using Jim Bridger Units 1, 2, and 3. The minimum stable operating levels for each of those three units is approximately 34 MW on average. In the TAM 2022 study, Jim Bridger's average dispatch price was [redacted]. If front office is confronting a market that offers only [redacted] per MWh, that would indicate that in order to simply break even the Company would have to be confident that prices would persist at that level (and that the Company could continue to reliably serve load without the resource in question) for approximately 53 days. The reason is simple: those units have a start charge of [redacted]. At a minimum stable output of only 34 MW, and a difference between the dispatch price and the market price of only [redacted] per MWh, the hourly savings would be just [redacted] per hour, meaning it would require a downtime of [redacted] in order to make a shutdown prudent. That of course leaves aside any potential reliability impacts, which the Company must also consider. This is the reason that most cycling activity takes place in the second quarter of each year. When hydro is plentiful and market prices are low, the likelihood of finding feasible and operationally responsible opportunities to economically cycle is greater.

Q. Sierra Club also believes that PacifiCorp's operational procedures will not mirror the TAM due to the removal of "must run" settings.[133] How do you respond?

A. The TAM process is not intended as a review of the Company's operational procedures or standards. The TAM Guidelines make clear that the TAM is designed to estimate prudent NPC costs for inclusion in Oregon rates, and sets a clear framework that excludes litigation of other issues.[134] Any discussion regarding these issues should be reserved for another proceeding.

Q. Do you agree with Sierra Club that the Commission should "closely examine" the Company's future PCAM filings to ensure "dispatch practices" were followed?

A. No. First, the Commission has clearly stated that the TAM and PCAM proceedings, while related, are separate proceedings that have "stabilized" in recent years.[135] The Commission also reiterated that it will not redesign the PCAM parameters until "around 2024."[136] This proceeding is the wrong forum for a discussion of PCAM

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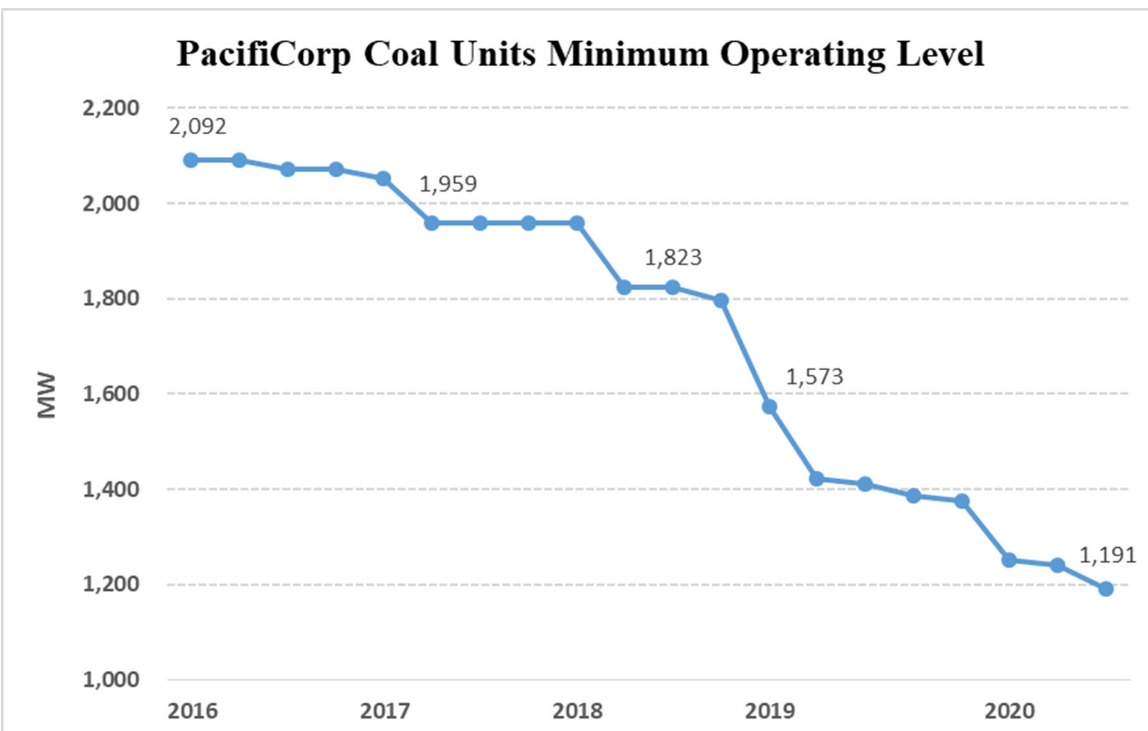
[133] Sierra Club/100, Burgess/9.
[134] 2009 TAM, Order No. 09-274, App'x A at 9.
[135] Order No. 20-473 at 129.
[136] Order No. 20-473 at 130.

procedures and the Commission has recently determined that the process will not be redesigned at this time.

Q. Do you agree with Sierra Club that the Company's inputs to adjust for "must run" settings led to economic losses on certain occasions?[137]

A. No. The Company does not allow coal units to cycle year-round in actual operations, and as discussed above, the TAM is intended to model short-term NPC for Oregon rates. As shown in Figure 6 below, the Company has adjusted the minimum operating levels of most of its coal plants in recent years to take advantage of increasing renewable generation for its customers.

Figure 5



[137] Sierra Club/100, Burgess/23.

The results of these operating changes, along with the continued increase in renewable generation, can be seen in the consistent reduction in coal generation year over year.

Further, the only analysis offered to support the assertion was a series of approximately five days in 2020 when, by Mr. Burgess' calculations, Jim Bridger operated at a loss of approximately [redacted] in total. The point that is missed by Mr. Burgess in that analysis is that Jim Bridger wasn't operating at minimum in the series of days he examined, and he substituted TAM average prices for the more appropriate incremental prices. If volumes were held at the lowest possible output, even with the elevated fuel prices, operating the plant *still* would have been profitable compared to a decision to cycle.

Q. Sierra Club asserts that PacifiCorp could economically benefit by cycling coal resources.[138] Do you agree?

A. No, for all the reasons stated above. If the Company believed it could save money and meet North American Electric Reliability standards without unduly creating risk, it would do so.

2. Bridger Coal Contract Costs

Q. What is Sierra Club's claim regarding how PacifiCorp reflects BCC costs in modeling NPC in GRID?

A. Sierra Club claims that the 2022 dispatch tier for Jim Bridger is [redacted] lower than the costing tier in GRID. Sierra Club argues that the single dispatch tier fuel price at

[138] Sierra Club/100, Burgess/24–25.

Jim Bridger deviates significantly from "true marginal cost" of the BCC or Black Butte coal supply.[139]

Q. How do you respond?

A. The Company applies dispatch costs for coal on an annual basis, which is aligned with the TAM forecast period, the annual coal supply requirements in the underlying contracts, and the BCC supplemental contract. Because incremental costs are applied on an annual basis, GRID will dispatch one coal unit over another in all hours if the incremental price is lower. The incremental price associated with the BCC supplemental contract reflects the marginal production cost at the mine as described in Mr. Ralston's reply testimony.

Q. Sierra Club asserts that the Commission should consider whether an accelerated closure of BCC is in the interest of Oregon ratepayers.[140] Do you agree with this statement?

A. No. First, a discussion about the accelerated closure of any PacifiCorp facility is well outside the parameters of a TAM proceeding and should be evaluated in PacifiCorp's long-term mine plan and IRP processes. Second, BCC is already planning on closing the underground mine at the end of 2022, consistent with the long-term mine plan filed with the Commission. Third, the Commission has approved exit dates for Jim Bridger of December 2023 for Unit 1 and December 2025 for Units 2-4. Mr. Ralston also addresses this issue in his reply testimony.

[139] Sierra Club/100, Burgess/51.
[140] Sierra Club/100, Burgess/55.

Q. What is the process that Sierra Club recommends that PacifiCorp use to more accurately model Jim Bridger fuel costs and associated generation?

A. Sierra Club recommends that because BCC has no minimum take quantities, the marginal fuel cost in GRID should reflect a weighted average of the full cost of coal from both the Black Butte and BCC base sources. Based on Sierra Club's initial calculations, a [redacted] percent reduction in BCC costs may be warranted due to fixed costs as well as a small adjustment for 2021 coal deferred from Black Butte. Even with these adjustments, Sierra Club believes that the marginal cost should be higher than the [redacted] per million British thermal units used in the 2022 TAM.

Q. Do you agree with this recommendation?

A. No. First, Sierra Club once again recommends using average costs instead of incremental costs as an input to the analysis, which is contrary to basic economic principles. Second, Sierra Club's suggestion that benefits would accrue to ratepayers if Jim Bridger were dispatched at average costs instead of incremental costs is entirely incorrect and relies on a gross mischaracterization of the Company's response to a data request, as I will explain below.

Q. Sierra Club suggests that there is no minimum take requirement for BCC because it is an affiliate mine.[141] Do you agree?

A. Yes, but while BCC does not have a minimum take requirement, it does have fixed costs that function like a minimum take requirement in the Company's modeling. Incorporating these fixed costs into GRID ensures the lowest costs for customers. This modeling is standard procedure for mine contracts and mining operations.

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[141] Sierra Club/100, Burgess/51.

Q. How would you define fixed costs?

A. Costs that do not vary across a range of possible production levels. Expenses that fit into this category can vary across a range of possible time periods.

Q. Does Sierra Club adhere to this definition?

A. Not entirely. At one point, Sierra Club suggests that fixed costs could be reduced based on lower production volumes at BCC.[142] Interestingly, they quote the Company's own data request to support the assertion, even though that response notes that "from the prism of a one-year test period such as the transition adjustment mechanism (TAM) filing, the majority of labor costs [redacted] would be considered fixed."[143]

Q. Sierra Club seems to suggest that PacifiCorp has made incorrect assumptions about Jim Bridger costs in its modeling.[144] Do you agree?

A. No. Black Butte is subject to a minimum take requirement and BCC has reasonable fixed costs which act like a minimum take provision for modeling purposes. Neither of these facts indicate incorrect modeling assumptions.

Q. In Confidential Table 9, Sierra Club totals BCC fixed costs at [redacted].[145] Does this number include all BCC's fixed costs?

A. No and the number directly contradicts the Company's response to Sierra Club's data request. In Data Request 2.5(c), PacifiCorp listed "wholly identifiable fixed costs" at [redacted] but went on to state that "[o]ther fixed costs are embedded in labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs

[142] Sierra Club/100, Burgess/58.
[143] Sierra Club/112, Burgess/6.
[144] Sierra Club/100, Burgess/52.
[145] Sierra Club/100, Burgess/56.

that are independent of coal production activities."[146] The response notes that those costs would be required in order to comply with Mine Safety Health Administration and Wyoming Department of Environmental Quality requirements. The response further noted that for a short-term test period like a TAM, the majority of labor costs are considered fixed. The total fixed costs would be, at minimum, [redacted], which is reflected in the Company's response to the data request.

Q. What erroneous conclusions does Sierra Club attempt to introduce into the record on the basis of this mischaracterization?

A. Specifically, Mr. Burgess' testimony that "when the full coal fuel costs are accounted for in GRID, it can actually lead to a net reduction in NPC"[147] is incorrect. That conclusion rests entirely on the supposition that BCC fixed costs were only [redacted].

Q. Regarding fixed costs, do you agree with Sierra Club's position that the Commission should conduct a comparison of PacifiCorp's base rates and TAM to ensure no depreciation costs for BCC are included in both recovery mechanisms?

A. No. Any study would be unnecessary and outside the scope of this proceeding. The Commission already determined it would not adopt any changes to the TAM Guidelines in PacifiCorp's last general rate case.[148] PacifiCorp is not recovering for the depreciation of BCC in base rates and the TAM despite Sierra Club's unsupported assertions.

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[146] Sierra Club/112, Burgess/6.
[147] Sierra Club/100, Burgess/67.
[148] Order No. 20-473 at 130 ("[The Commission] declines to adopt any changes to the TAM guidelines, as requested by PacifiCorp and the parties.").

Q. Sierra Club asserts that because PacifiCorp self-determines the price and quantity of its supplemental fuel from BCC it is able to "game the supplemental pricing to its own advantage."[149] Please respond.

A. Many decades ago, the Commission consolidated BCC on PacifiCorp's balance sheet to avoid any possibility of self-dealing and to ensure that BCC coal supply was priced on an actual cost (not market) basis.[150] Sierra Club's position ignores this important regulatory context.

Q. Do you agree with Sierra Club's position that "PacifiCorp should only assume the supplemental price is in effect if it is evident that both the BCC base quantity and Black Butte quantity will be exhausted in the NPC forecast year"?[151]

A. No. GRID would select alternative resources with a cost lower than BCC's base plan but higher than BCC's incremental cost because the model would not recognize the availability of BCC's lower cost incremental production. Customers would pay for BCC base costs and not benefit from leveraging the full benefits of mine ownership because BCC incremental coal would not be dispatched. The net result would be higher costs paid by customers.

Q. Sierra Club criticizes the Company's decision to add back in some fixed costs through a "reaveraging" step in its 2022 TAM using average costs, including some of the BCC fixed costs.[152] How do you respond?

A. As PacifiCorp explained in its data request, without a reaveraging step, a GRID run is not valid as an NPC evaluation because the numbers are not inclusive of all cost

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[149] Sierra Club/100, Burgess/61.
[150] *Re Pacific Power & Light Company*, Docket No. UF 3779, Order No. 82-606 at *11–14 (Aug.18, 1982).
[151] Sierra Club/100, Burgess/62.
[152] Sierra Club/100, Burgess/66–67.

components.[153] As explained above, these fixed costs are not "distortions" of the model because they represent typical costs associated with mining that the Commission has approved for years.

Q. Sierra Club claims it is inappropriate for iOpt to assume BCC supplemental pricing for all coal fuel consumed at Jim Bridger because PacifiCorp would only need to purchase supplemental coal after the base quantity for BCC was consumed and the minimum take for Black Butte has been satisfied; thus, it effectively results in a customer subsidy.[154] How do you respond?

A. The take-or-pay provision in the Black Butte contract, and the fixed costs that are accounted for in the BCC mine plan effectively make them both part of a combined base fueling plan, so treating them as such is appropriate and cost-minimizing. As described in Mr. Ralston's reply testimony, the average costs at Jim Bridger are higher than the incremental costs because they include the fixed costs of the BCC mining operations necessary to produce minimum mine plan volumes. The Company applies dispatch costs at Jim Bridger based on the BCC supplemental contract because it represents the marginal cost associated with procuring additional coal above the minimum mine plan volumes coupled with the Black Butte contract.

Q. Sierra Club notes that Jim Bridger actual dispatch was higher than iOpt forecasts for the period of January 2019 through May 2020.[155] Is it reasonable for actual Jim Bridger plant dispatch to differ from iOpt forecasts?

A. Yes. As Sierra Club correctly notes, "While the iOpt/PCI outputs serve as a starting

[153] Sierra Club/103, Burgess/9.
[154] Sierra Club/100, Burgess/69–70.
[155] Sierra Club/100, Burgess/71–72.

point, PacifiCorp's energy traders may then make different decisions during actual operations due to changes in system conditions since the completion of the model run."[156]

Q. Why would actual Jim Bridger dispatch differ from an iOpt forecast?

A. There are several possible reasons, and they are not mutually exclusive. First, the iOpt model calculated an optimal physical system position using market prices, fuel costs, forecasted customer loads, forecasted hydro, wind, and solar generation, generating resource characteristics, physical system constraints, contractual obligations, and reserve holding requirement assumptions available at the time the model was run. The process of uploading these inputs and forecasts to the iOpt model, performing a simulation, and retrieving and summarizing these results required several hours or more and therefore was performed once per business day as part of the middle office department's end of day processes. These limitations resulted in a minimum of 12 hours from the time these inputs and forecasts were uploaded until the beginning of the following trading day, with even longer delays for the beginning of the trading week or after holidays. Many of these inputs and forecasts—particularly market prices, forecasted customer loads, unit availability, and forecasted variable energy resources (VER)—change materially over the time from the preparation and upload of these inputs to the following trading day, and necessitate different approaches to meet system obligations than what was initially proposed from the iOpt model data. The traders utilized the iOpt results combined with current market conditions and load and resource forecasts, as well as using their

[156] Sierra Club/100, Burgess/69–70.

experience and knowledge to make unit commitment and dispatch decisions to meet system obligations in the most safe, reliable and economic manner possible.

Second, when system needs require additional generation, traders compare market purchases with dispatching owned resources. Jim Bridger's relatively low incremental unit cost makes it a competitive resource that can be used to meet these system obligations. In addition, with the increasing contribution of VER to the PacifiCorp system, having dispatchable resources to meet that uncertainty and the uncertainty around load is necessary to maintain system integrity. The enhancements to and expansion of the operating ranges at the Jim Bridger plant units allow PacifiCorp to economically dispatch these coal units up and down as needed while allowing the system to incorporate the uncertainty around the VER. In short, dispatchable resources make possible the integration of renewable, non-dispatchable resources into the Company's system. The iOpt model was purely deterministic in the same manner that GRID is, which means that it would satisfy the known obligations at the time the model was run, but in responding to an event unforeseen in the prior day's iOpt model run, flexible resources like Jim Bridger allow the Company to meet changing hourly requirements and departures from forecast. This primarily owes to the fact that the resource has such a wide range of possible operation.

Finally, the Jim Bridger plant's ability to reach both sides of the system (the PACE and PacifiCorp west balancing authority (PACW) balancing areas) easily makes it an immediate candidate as a response unit almost anywhere. That added flexibility is also considered by the Company in determining the most prudent dispatch decisions in actual operations.

Q. Is there anything else worth noting about Sierra Club's analysis of actual dispatch practices?

A. Yes. Demonstrating that Jim Bridger's operations deviated from the prior day's model run is not meaningful or indicative of uneconomic practices. The iOpt model is the starting point for the development of a dispatch plan, not a dispatch plan in and of itself.

Sierra Club similarly failed to consider operational feasibility, did not acknowledge the changing requirements of the system, which must be balanced in real time, and never once presented evidence that market liquidity existed in sufficient quantities to balance the system without using a dispatchable resource to do so. The only evidence that was introduced is a series of model runs, the results of which were outdated before Company personnel ever had an opportunity to analyze them.

Q. In response to the difference between energy trader forecasts and the TAM, Sierra Club recommends that the Commission require an accounting of energy trader fuel cost assumptions as part of the TAM and PCAM. How do you respond?

A. Once again, this issue is outside the scope of this docket. Tracking of energy trader forecasts does not correspond to TAM projections or resource costs, which is the focus of this docket. Further, any discussions regarding PCAM proceedings should be addressed in the PCAM docket as the TAM and PCAM are separate recovery mechanisms.

3. Response to Sierra Club's Recommendation for Future TAMs and other Recommendations

Q. Does Sierra Club provide any recommendations for future changes to PacifiCorp's filing requirements in future TAM proceedings?

A. Yes. Sierra Club recommends that the Commission require PacifiCorp to:

- provide a tracking report detailing daily unit commitment and dispatch decisions for each of its thermal plants throughout 2022;
- include a report on the steps the Company has taken to reduce BCC costs; and
- provide copies of its CSAs and affiliate mine plans.[157]

Q. Specifically, what would Sierra Club require in this proposed tracking report?

A. Sierra Club would require the Company to include details on: (1) marginal fuel costs assumed by PacifiCorp's energy traders, (2) expected operating costs, (3) expected market price, (4) whether the plant was operated as "must run" or economically committed, and (5) what the assumed cycling costs were.

Q. How do you respond to these recommendations?

A. First, as Sierra Club conceded, PacifiCorp's energy traders make decisions during actual operations that differ from the model run for various reasons associated with the complexities of actual operations not accounted for in any model.[158] Once again, as detailed above, any further discussion on actual operational decisions is outside the scope of a TAM proceeding, which is focused on expected costs based on GRID model projections.[159]

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[157] Sierra Club/100, Burgess/3–4.
[158] Sierra Club/100, Burgess/69–70.
[159] *See* 2009 TAM, Order No. 09-274, App'x A at 9.

Second, PacifiCorp has already provided its projected operating costs as detailed in the GRID report for the 2022 TAM. Any further runs conducted throughout 2022 would be onerous and would not provide meaningful data to the Commission and intervenors that cannot be obtained post hoc during the PCAM proceeding.

Third, expected market costs vary constantly over time and have limited utility in providing a rationale for actual dispatch decisions, given that those decisions are based on actual data, not expectations or forecasts.

Finally, information on whether individual coal units were "economically committed" or cycled during actual operations is outside the scope of the TAM proceeding, which does not focus on actual operation costs. These discussions should be reserved for the PCAM proceeding, which is designed to address differences between projected and actual operation costs.

Q. How do you respond to Sierra Club's recommendation to require individual reports on BCC costs in future TAMs?

A. This recommendation should be rejected for the reasons outlined above and in the reply testimony of Mr. Ralston and Mr. Schwartz. BCC coal costs are properly accounted for in the GRID model and any further discussion of the prudence of these costs should be addressed in PacifiCorp's long-term mine plan or IRP processes.

Q. Do you agree with Sierra Club's recommendation to provide CSAs and affiliate mine plans as part of future TAM proceedings?

A. No. As outlined in Mr. Ralston's reply testimony, the Commission has already established a process to review fueling strategies for the Company's coal plants.

Q. Sierra Club claims that in PacifiCorp's California 2021 Energy Cost Adjustment Clause (ECAC) proceeding, Hunter's forecasted generation had to be manually adjusted in order to meet the minimum take obligation.[160] Is this correct?

A. This observation is irrelevant. Forecasted generation from the California 2021 ECAC filing has no relation to the accuracy of power costs in this proceeding. The test year for the 2021 ECAC filing is 2021 while the 2022 TAM is a 2022 test year.

VII. OTHER ADJUSTMENTS

A. <u>QF contracts</u>

Q. How does PacifiCorp forecast QF costs in the TAM?

A. The forecast for QF costs in the TAM is based on QF contracts with specific prices and terms. The contract may specify an exact quantity of capacity and energy, or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. Prices may also be specifically stated, may refer to a rate schedule or a market index, or may be based on some type of formula. Every QF contract is modeled individually. For QF contracts with a nameplate capacity greater than 10 MW, the delivery energy forecast is based on 48-month normalization assumptions. For QF contracts with a nameplate less than or equal to 10 MW, the delivery energy forecast uses the actual delivery schedule available before the filing. For renewable QFs with a nameplate greater than 10 MW, the forecasted capacity factor is based on either full history if the QF has been online longer than four years or based on P50 if the QF has been online shorter than four years.

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[160] Sierra Club/100, Burgess/44-45.

In addition, consistent with methodology change adopted in the 2018 TAM, PacifiCorp's QF forecast also includes an adjustment for the contract delay rate (CDR). The CDR is calculated based on the average days between the QF's expected commercial operation date (COD) in the final TAM and its actual COD (or more recently estimated COD) from the last three TAM cases, weighted by the size of the delayed QF. PacifiCorp applies the CDR to all the new QFs coming online in the test period.

Q. Has the CDR increased the accuracy of QF forecasting?

A. Yes. In the first year of the CDR's full application, the difference between forecast and actual QF costs was less than one-half of the difference of any other year within the previous four-year period.

Q. Please explain Staff's proposal to adjust PacifiCorp's QF contract costs.

A. Staff believes that PacifiCorp has a history of overestimating MWhs produced from QFs.[161] To account for this perceived historical overestimation, Staff proposes an adjustment that reduces NPC by approximately $1.53 million.[162]

Q. What is the basis for Staff's adjustment?

A. Staff compared actual QF costs to forecasted QF costs from 2016 through 2020 and concluded that PacifiCorp "has a history of overestimating [power] produced from PURPA QF projects."[163] Staff then took PacifiCorp's estimated QF purchased power cost on an Oregon-allocated basis and reduced it by difference between 2020's forecasted QF power costs and 2020's actual QF power costs, [redacted].[164] Staff

[161] Staff/500, Zarate/12.
[162] Staff/500, Zarate/14.
[163] Staff/500, Zarate/12.
[164] Staff/500, Zarate/12-13.

then accounted for replacement power costs to serve this additional load to arrive at a final adjustment of $1.53 million.[165]

Q. Do you agree with Staff's characterization that PacifiCorp's modeling consistently overestimates power costs?

A. Not to the degree described by Staff. As discussed above, once the Company implemented CDR, its QF power cost forecasts increased substantially in accuracy. Based on post-CDR data only, the Company's overestimation of QF power costs drops from [redacted] to [redacted].

Q. Is the modeling of new QFs with less than 48 months history consistent with the modeling treatment of wind resources for EV 2020?

A. Yes, resources from EV 2020 are modeled using the capacity factor developed at the time of the investment. New QFs with less than 48 months of history also use capacity factors based on the individual project's developer forecasts. Once a QF projects pass four years in service, the Company will use actual capacity forecasts based on historical output.

Q. Is Staff's generalized adjustment appropriate?

A. No, PacifiCorp is relying on the best individual information that is available for each QF project. A generalized adjustment would not capture the granularity that exists in PacifiCorp's current forecast.

B. <u>NPM</u>

Q. Please describe the Company's transition to a NPM.

A. As explained in Appendix D to the 2020 Protocol, PacifiCorp's NPM Memorandum

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[165] Staff.500, Zarate/13–14.

of Understanding, the Company began NPM service in January 2021. In approving the 2020 Protocol, the Commission emphasized "the high level of transparency" it expects with NPM.[166] Beginning in 2024, the Company will transition to NPM to track power costs.

Q. Please describe the NPM.

A. The NPM is a tool designed to track NPC by generation resources and by state under an inter-jurisdictional cost allocation that will no longer dynamically allocate costs among states based on their respective loads. Instead, generation-related costs will follow the assignment of those resources. PacifiCorp worked with the California Independent System Operator (CAISO) to produce the NPM. CAISO, acting as a third-party vendor, will produce optimal unit commitment and hourly energy schedules for supply resources in the PacifiCorp balancing authority areas (BAAs) using the CAISO day-ahead market model. PacifiCorp will use the NPM to track costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state for ratemaking purposes.

Q. Please describe conceptually how the NPM works.

A. The NPC associated with each generating resource will be assigned to states based on each generating resource's assignment. For example, if a state is assigned 25 percent of a natural gas plant, then it is also assigned 25 percent of the fuel costs associated with that resource, regardless of load. Each resource also receives a credit based on the locational marginal price (LMP) for its generation, which is also assigned to each

[166] *In the Matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 at 8 (Jan. 23, 2020).

state per its assignment of each generating resource. The assigned NPC, less the credit received, will be the states' total NPC.

Q. Please explain the credit received by each generating resource in more detail.

A. Each generating resource will receive a credit for the energy it generates or the reserves it provides, and each state's load will be charged a load aggregated point (LAP) price.[167] The total credits the generating resources receive will equal the dollar amount that each state's load is charged. This facilitates a transfer of energy between states at a fair price based on the LMP and preserves the benefits of a system dispatch and optimization.

Q. What is the current status of the NPM?

A. The Company began using the NPM on January 15, 2021. Because CAISO is acting as a third-party vendor for the NPM, the Company began paying CAISO an $8.4 million annual service fee this year.

Q. Please describe Staff's proposed adjustment based on the NPM.

A. First, while Staff acknowledges that tracking and forecasting of costs will not begin until 2024, Staff argues that "efficiency gains resulting from the new dispatch logic should be passed onto customers in 2022 NPC rates."[168] To account for these unquantified benefits, Staff recommends that the NPC forecast be reduced by $8.4 million, or the amount paid to CAISO in annual service fees for the NPM.[169]

Q. Did Staff quantify the alleged benefits from the NPM for 2020 NPC?

A. No. Staff neither quantified its adjustment nor provided any proposed methodology

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[167] The LAP price is the weighted average LMP at each load point or node within the LAP.
[168] Staff/900, Gibbens/12.
[169] Staff/900, Gibbens/12.

for determining the alleged benefits. Instead, Staff simply points to the CAISO service fee as an incremental cost to match the alleged benefits without any discussion of how the unquantifiable benefits are related to the Company's NPM annual service fee.

Q. Does the Company agree that the NPM will result in more efficient resource dispatch in actual operations?

A. Yes, but any efficiency gains resulting from the NPM are already included in the GRID forecast because of GRID's perfect optimization. The NPM will allow real operations to more closely match GRID's perfect optimization more accurately.

Q. Please explain how the GRID model assumes perfectly efficient operations.

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

Q. How do actual operations depart from GRID?

A. In actual operations there is not perfect foresight and uncertainty exists. In other words, human operators are making dispatch decisions based on the best available information. That information, however, is inherently imperfect and a human operator is therefore making dispatch decisions without perfect foresight into system conditions, which are constantly changing. While the Company will experience benefits from the NPM in its actual operations, those benefits will only bring actual costs closer to the ideal dispatch calculated in the GRID model. Therefore, PacifiCorp's modeled NPC already incorporates dispatch savings compared to the Company's actual operations. Imputing incremental NPM dispatch benefits outside of GRID is therefore unreasonable.

Q. Staff analogizes the NPM to PacifiCorp's participation in the EIM.[170] How do you respond to that analogy?

A. The Company agrees that the NPM is analogous to the Company's participation in the EIM; but that does not support the imputation of additional benefits that drive down the forecasted NPC. Although Staff broadly references EIM benefits, the NPM is closely analogous to the *intra-regional* benefits that are not imputed as an EIM benefit outside of GRID.

Q. Please describe the intra-regional EIM benefits.

A. Intra-regional EIM benefits result from the more optimized dispatch of the Company's generation within its BAAs. These benefits are different from the *inter-regional* benefits, which result from cost-effective transfers between PacifiCorp and other EIM participants and that are the subject of the outside-GRID EIM adjustment in the TAM.

Q. Has the Commission addressed the treatment of intra-regional EIM benefits in the TAM?

A. Yes. In the 2017 TAM (docket UE 307), Staff and CUB recommended an adjustment to impute intra-regional EIM benefits.[171] In that case, the Company explained that because GRID is already perfectly optimized, in every hour the lowest cost resources will be dispatched, subject to transmission constraints, and the intra-regional benefits

[170] Staff/900, Gibbens/12.
[171] 2017 TAM, Order No. 16-482 at 15.

manifest as a decrease in the Company's actual, not modeled, NPC.[172] Thus, PacifiCorp testified that the intra-regional benefits are real, but they are already built into the Company's overall NPC forecast. In other words, the more efficient dispatch that has always been reflected in the GRID model could now be achieved in actual operations.

Q. How did the Commission address intra-regional benefits in the 2017 TAM?

A. The Commission rejected the imputation of intra-regional benefits after concluding that the "GRID forecast already accounts for intra-regional benefits because the model optimizes dispatch on an hourly basis."[173]

The same is true here. The use of the NPM to more efficiently dispatch resources in actual operations will bring actual costs closer to the ideal dispatch calculated in GRID. Because these benefits are already included in the NPC forecast, the imputation of additional benefits would be double-counting and have no relation to the proposed $8.4 million adjustment.

C. <u>PacifiCorp's EIM Benefits Model</u>

Q. Did Staff allege any inconsistencies with the Company's EIM benefit models?

A. Yes. Staff has two primary concerns with PacifiCorp's EIM benefits models. First, Staff believes that the Company transformed its variables using natural gas logs and exponentiation in its import regressions while employing polynomial transformations in its two export regressions. Staff could not determine why these two different

[172] *See Id.* at 15-16 ("PacifiCorp does not include intra-regional benefits in the TAM because it states that GRID has always reflected perfectly optimized dispatch. . . . PacifiCorp maintains that intra-regional benefits are inherent in the GRID forecast and imputing additional benefits is double-counting[.] PacifiCorp states that the intra-regional benefits are real, but they only bring actual costs closer to the ideal dispatch calculated GRID.").
[173] *Id.* at 16.

approaches were used for modeling essentially the same process.[174] Staff also believes that the Company's error term may introduce estimation problems into its benefit model.[175]

Q. Please briefly describe the Company's four EIM benefits models.

A. The Company employs four different EIM benefits models: (1) the PACE Export model, (2) the PACW Export model, (3) the PACE Import model, and (4) the PACW Import model. These various components reflect the different potential sources of EIM benefits and allow each to be forecasted independently of one another.

Q. Did Staff believe the Company had properly set up its regression models?

A. Not entirely. Staff was satisfied with the method PacifiCorp used to set up its [redacted] and recommended no change to the Company's [redacted][176] Staff, however, did recommend an adjustment to PacifiCorp's [redacted].

Q. What modification did Staff recommend to PacifiCorp's [redacted]?

A. Staff proposed reconfiguring the Company's [redacted] to rely on [redacted][177] This change to the [redacted] lowers PacifiCorp's total energy transfer benefit by $452,000 on an Oregon-allocated basis.[178]

[174] Staff/800, Dlouhy/10.
[175] Staff/800, Dlouhy/13-14.
[176] Staff/800, Dlouhy/16–19.
[177] Staff/800, Dlouhy/19.
[178] Staff/800, Dlouhy/23.

Q. Do you agree with Staff proposed modification and adjustment?

A. Yes, the proposed adjustments minimize error, and are reasonable as explained by Mr. Dlouhy in his testimony.

Q. Staff witness Enright raises a concern that PacifiCorp has not been appropriately forthcoming in EIM related data requests. Does PacifiCorp have a response?

A. Yes. PacifiCorp is committed to working with Staff and providing the necessary information for Staff to appropriately review PacifiCorp's filing. However, PacifiCorp responded to 180 data requests (which is of significantly higher volume that past TAM proceedings) from Staff, 43 of which specifically dealt with EIM (and often included multiple sub-parts). PacifiCorp spent tens of hours pulling together the data that was requested by Staff, and is therefore disappointed that Staff feels that the Company has not been appropriately forthcoming.

D. <u>PacifiCorp's forecast of GHG Benefits</u>

Q. Did Staff have recommendations regarding the Company's methodology for forecasting GHG benefits in the Initial Filing?

A. Yes. Staff has three suggestions for revisions to the Company's GHG benefit forecast. First, Staff suggests using a longer period of historical data to estimate GHG benefits, for which they anticipate a decrease in total-company NPC of approximately [redacted].[179] Second, Staff proposes the application of two years of growth rate to the 2022 forecast, for which they anticipate a decrease in total-company NPC of approximately [redacted].[180] Finally, Staff proposes that the GHG

[179] Staff/100, Enright/35.
[180] Staff/100, Enright/32.

growth rate be applied to all generation sources instead of only the hydro resources, for which they anticipate a decrease in total-company NPC of approximately [redacted].[181]

Q. Does the Company accept these changes in methodology?

A. Partially. The Company accepts the first two modifications, as they're well-supported and logical. However, in making the changes to the forecast workbook, the Company only observed a change of approximately [redacted], which is somewhat below the expected increase to benefits reflected in Staff's testimony. We invite a review of the updates made to the model and subsequent feedback to ensure that the Company is aligned with Staff's recommendation on this issue, because we agree with the proposal in principle but were unable to duplicate the anticipated impacts.

Q. Has the Company accepted or rejected the proposed change to allow the growth rate to impact benefits from all generation sources, as opposed to only hydro generation sources?

A. The Company is still collecting data and analyzing the suitability of Staff's proposal. However, for the purposes of this TAM proceeding, PacifiCorp proposes to incorporate the impact calculated by Staff, but on a non-precedential basis in order to further research the topic. PacifiCorp will continue to review this issue and provide a revised proposal in the 2023 TAM filing.

[181] Staff/100, Enright/38.

E. Relationship between EIM Trades

Q. Staff has requested information from the Company regarding "what perceived relationship may exist between [forecasted balancing trades, actual balancing trades, and EIM trades]" including reliable and transparent information.[182] How does PacifiCorp respond?

A. The Company has made clear above, the relationship between forecasted and actual trades is that forecasted balancing activity has historically been overstated due to the use of the maximum of averages approach regarding market caps. Establishing a relationship to EIM volumes is not possible because, while the benefits of EIM participation are forecasted using the methodology covered in Mr. Dlouhy's testimony, that forecast does not include a volumetric component. The Company is not capable of forecasting EIM volumes as it does not have the necessary information for the entire EIM footprint or the tools necessary to produce an EIM optimization, and such a forecast would yield no incremental benefit in forecasting precision since the benefits are already appropriately included in NPC.

F. Natural Gas Costs and Optimization Margins

Q. How does PacifiCorp calculate its natural gas pricing in the TAM?

A. The Company used its OFPC from December 2020 to estimate its natural gas prices for the 2022 TAM. The Company derives the OFPC from a combination of forward market prices on a given quote date and long-term fundamentals-based price forecast. The entire OFPC for the 2022 TAM is based on broker quotes. Prices used to model the TAM are required to be within five percent of the broker average.

[182] Staff/100, Enright/46.

Q. Does Staff believe that PacifiCorp based its natural gas pricing on any other metrics?

A. Yes. Staff believes that PacifiCorp also relied on natural gas futures pricing from the Wall Street Journal to estimate its natural gas costs in the 2022 TAM.[183]

Q. Do you agree?

A. No. As the Company explained, the reference to the Wall Street Journal's Henry Hub index was related to the Cholla CSA and had no relation to natural gas pricing.[184] PacifiCorp has since closed operations at Cholla and the index had no bearing on the 2022 TAM.

Q. Does Staff have any concerns about the way the Company optimizes natural gas prices?

A. Yes. Staff was unable to determine whether PacifiCorp shares its optimization proceeds with customers. Specifically, Staff could not determine whether the Company shares benefits from arbitrage activity and whether optimization proceeds offset future expenses.[185]

Q. How does the Company optimize its natural gas supply?

A. The Company hedges natural gas supply in the forward price markets based on anticipated fuel requirements. At the time of delivery, market conditions may change and, if the spot market spark spread is negative, the dispatch plan for one or more resources may be altered, which allows the Company to economically sell previously purchased natural gas while still meeting system needs from other resources.

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[183] Staff/400, Fjeldheim/4.
[184] Staff/402, Fjeldheim/4.
[185] Staff/400, Fjeldheim/9–10.

Engaging in this optimization helps provide better power pricing for PacifiCorp customers.

Q. Are all the costs and benefits of the Company's natural gas hedging reflected in Oregon rates?

A. Yes. Because the gas optimization discussed above typically amounts to the remarketing of previously purchased gas when economic, to the extent that optimizing physical gas is possible in actual operations, the benefits of that optimization can be reasonably approximated by considering the amount of the mark-to-market (MTM) value of the physical hedges executed by the Company. When consuming the fuel in operations, it represents the extent to which actual costs differ from market (GRID assumes a market price for consumed gas, so this is necessary to reflect any hedging costs or benefits), and when remarketing the gas as part of a decision to reduce or eliminate generation at one or more units, it represents the margin (positive or negative) that will be generated by the sale. The MTM of physical and financial hedges are both included in the TAM forecast. In this case, there are no physical gas hedges for the test period. That may change prior to the final TAM study in November.

Q. Can the Company optimize natural gas prices to benefit customers in the 2022 TAM?

A. No. The Company has not hedged any physical gas over the test period and it cannot optimize a financial gas position. To the extent that physical gas hedges are executed, the MTM values will be reflected in the GRID study results, increasing or decreasing

NPC based on the comparison of current market prices and the prices of those physical hedges.

G. Wheeling Costs

Q. How does the Company forecast wheeling costs?

A. In the Initial Filing, PacifiCorp based its wheeling costs on a 12-month historic period between July 2019 and June 2020. Wheeling costs from July 2020 to December 2020 were not available at the time of the direct filing because those costs are typically updated during the semi-annual model update, which was not complete before the Initial Filing was completed. In the Reply Update study filed along with this testimony, the costs from July 2020 to December 2020 were updated, along with several updates intended to reflect the anticipated impact of the recently settled BPA rate case.

Q. Does the Company calculate all wheeling expenses using the same methodology?

A. No. Measured in sheer numbers, most wheeling expenses are based on 12 months of history. However, to the extent that a change in expense is known and measurable (typically as a result of some contractual mechanism), those costs are escalated in keeping with the contract itself. In addition, to the extent that some wheeling items are certain to increase because of a rate escalation from a rate case filing, those expenses are forecasted on a forward-looking basis.

Q. Has Staff questioned any of these wheeling expenses?

A. Yes. Staff has identified three separate wheeling paths that require further inquiry: (1) the [redacted], (2) the [redacted], and (3) the [redacted]S.

Q. What is the [redacted]?

A. In the context of the wheeling file that Staff has inquired about, it [redacted]

Q. Does Staff recommend an adjustment for the Company's [redacted] line item?

A. Yes. Staff believes that the Company's [redacted] expense is not calculated with the most accurate data based on actual 2020 wheeling expenses and data from 2021.[186] Staff contrasts to the Company's calculations for [redacted] calculations, where the Company relies on more recent data. Using the most recent data, Staff recommends an adjustment of [redacted] per month for the [redacted] line item.[187]

Q. Do you agree with Staff's recommendation?

A. No. [redacted]

[186] Staff/300, Hanhan/6.
[187] Staff/300, Hanhan/5.

[redacted]

Q. What is the [redacted] line item?

A. The [redacted] PacifiCorp uses a 12-month historical window to project costs and benefits for the test period which is consistent with how line items that do not exhibit known and measurable changes are treated.

Q. Staff also expressed concern about the recent increases in wheeling costs associated with [redacted][188] **Please explain these costs.**

A. The Company relies in part on [redacted] The reasons that these expenses have increased in recent history are:

[redacted]

H. <u>PTCs</u>

Q. The Commission's Issues List requested feedback on PacifiCorp's reporting on PTCs and the NPC savings realized from these credits. Does Staff believe that PacifiCorp complied with this requirement?

A. Yes. Staff believes that the Company's PTC report in its Initial Filing was consistent

[188] Staff/300, Hanhan/7–8.

with the Commission's directive.[189] However, Staff recommends that the Company provide a direct comparison between "the forecasted NPC benefits of the Company owned-wind projects and the benefit forecasts made to justify the investment."[190]

Q. What are the projected benefits from PTCs in the Company's 2022 TAM?

A. The Company has provided Confidential Exhibit PAC/103 to show the forecasted increases in PTCs based on the PTC level established in the 2021 TAM. On an Oregon-allocated basis, PTCs have increased by [redacted] from the 2021 TAM. This number includes 1,150 MW from new projects in EV 2020, such as TB Flats, Cedar Springs II, Ekola Flats, and a PPA with Cedar Springs I. The 2022 TAM also includes the 240 MW Pryor Mountain wind project and the 133.3 MW Cedar Springs III PPA. The total forecasted NPC benefit of the new resources is approximately $111 million.

Q. Is PacifiCorp willing to provide a comparison between these projected benefits in the 2022 TAM and the PTC benefit forecasts made to justify investment from the 2017 IRP?

A. EV 2020 will be entirely in service in 2022, and the TAM is showing significant benefits for customers. PacifiCorp does not believe that this comparison is necessary but can provide this analysis after the Final TAM update is filed if the Commission determines it is necessary.

[189] Staff/100, Enright/17; Staff/900, Gibbens/6.
[190] Staff/900, Gibbens/6; Staff/100, Enright/18.

Q. AWEC proposes an adjustment that decreases NPC by $2.6 million because it believes that the PTC rate will increase to 2.6 cents per kilowatt-hour due to projected inflation in 2021.[191] Do you agree with AWEC's adjustment?

A. Yes. The Company agrees that the PTC rate is likely to increase and will be incorporating that change from this point forward in the remainder of the 2022 TAM proceeding.

I. <u>Other Revenues and Fly Ash Sales</u>

Q. Has PacifiCorp included an Other Revenue adjustment in previous TAM proceedings?

A. Yes. Since 2010, PacifiCorp has agreed to include an Other Revenue adjustment in TAM filings in years where it does not file a general rate case.[192] The Commission defined the Other Revenue adjustment as "forecast changes . . . for items that have a direct relation to NPC."[193]

Q. Did PacifiCorp include an Other Revenue adjustment in the 2022 TAM?

A. An update to Other Revenue was not included in PacifiCorp's Initial Filing. However, upon further review the Company realized the one remaining contract for Other Revenue that is updated in the TAM will expire at the end of 2021. Therefore, an update to Other Revenue to reflect this change is included in the Reply Update.

[191] AWEC/100, Mullins/7–8.
[192] 2011 TAM, Order No. 10-363, App'x A at 4.
[193] *Id.* at 3.

Q. AWEC Points out that the Company reported revenue from a contract with Seattle City Light for the Stateline wind farm in its 2021 Rate Case.[194] Has PacifiCorp terminated this contract?

A. Yes, PacifiCorp should have reflected the termination of this contract in Other Revenue.

Q. Does the Stateline contract impact the Company's wind-based ancillary services revenue in the 2022 TAM?

A. Yes, PacifiCorp has made the adjustment to reflect this in the TAM. This increases the TAM by approximately $3.0 million.

Q. AWEC also believes that increased revenues from fly coal ash should be included as part of Other Revenue.[195] Do you agree with this inclusion?

A. Revenues from fly ash have traditionally been included in base rates and updated in general rate cases. If AWEC would like to move these revenues into the TAM, such a proposal should be made as a change to the TAM Guidelines in PacifiCorp's next general rate case.

Q. Based upon its analysis of the Company's Other Revenue, AWEC proposes an adjustment of $949,615 to Oregon-allocated TAM revenues.[196] Do you agree with this adjustment?

A. No, the Commission should decline to adopt this adjustment. The inclusion of Fly Ash revenue in the TAM can be reexamined in a general rate case.

[194] AWEC/100, Mullins/20.
[195] AWEC/100, Mullins/20.
[196] AWEC/100, Mullins/21.

J. <u>BCC Materials and Supplies</u>

Q. AWEC also recommends an adjustment of $785,644 to NPC based on the Company's "consistent history of overestimating materials and supplies expenses" at BCC.[197] Do you agree with this adjustment?

A. No. As discussed above and in the reply testimony of Mr. Ralston, BCC costs are estimated accurately and reflect prudently incurred expenses as part of PacifiCorp's generation portfolio. While the Company did overestimate BCC costs in 2020, the Company still under-recovered its NPC by $28 million. AWEC should not be able to cherry pick a single line item and single it out for scrutiny when the Company continues to under-recover its NPC year after year.

VIII. 2023 TAM FILING DATE CHANGE

Q. Does CUB propose a change to the 2023 TAM filing date?

A. Yes. CUB believes that with the Company's change from GRID to AURORA, parties will need more time to review the more complicated forecasting and the Company's shift to the NPM. To provide for a more thorough review of these new procedures, CUB proposes shifting the filing deadline for the 2023 TAM to January 15, 2022.[198]

Q. Do you believe that a shift to the filing date is necessary to accommodate a review of the AURORA model?

A. No. As detailed above, the Company plans to conduct workshops to answer all questions from parties surrounding the switch to the AURORA model and its effect on the 2023 TAM proceeding. PacifiCorp hopes that CUB, Staff, and all other

[197] AWEC/100, Mullins/22–23.
[198] CUB/100, Jenks/18.

interested parties can take part in these workshops to resolve many questions with the AURORA model before the 2023 TAM.

Additionally, changing the 2023 TAM filing deadline may affect the accuracy of the TAM modeling process. For instance, the deadline change would preclude the use of the December 31 OFPC, which increases the intra-year variability due to updates, and it puts the Company in the awkward position of preparing next year's TAM prior to the finish of the current year's TAM. If the intention is simply to increase CUB's understanding of the modeling before starting next year's proceeding, a guided tour of the specific modeling approach chosen by the Company would likely be of greater use than a few extra months of undirected exploration.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/401
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Douglas R. Staples

2022 TAM Oregon-Allocated Net Power Costs Reply Filing

July 2021

PacifiCorp
CY 2022 TAM
Reply Filing

Line no		ACCT.	Total Company UE-375 CY 2021 - Final Update	Total Company TAM CY 2022 - Initial Filing	Total Company TAM CY 2022 - Reply Filing	Factor	Factors CY 2021	Factors CY 2022	Oregon Allocated UE-375 CY 2021 - Final Update	Oregon Allocated TAM CY 2022 - Initial Filing	Oregon Allocated TAM CY 2022 - Reply Filing
1	**Sales for Resale**										
2	Existing Firm PPL	447	7,802,619	7,588,544	7,568,265	SG	26.023%	26.482%	2,030,447	2,009,566	2,004,196
3	Existing Firm UPL	447	-	-	-	SG	26.023%	26.482%	-	-	-
4	Post-Merger Firm	447	341,463,801	244,865,802	314,709,782	SG	26.023%	26.482%	88,857,870	64,844,327	83,340,115
5	Non-Firm	447	-	-	-	SE	25.101%	25.369%	-	-	-
6	**Total Sales for Resale**		349,266,420	252,454,345	322,278,047				90,888,317	66,853,893	85,344,311
7											
8	**Purchased Power**										
9	Existing Firm Demand PPL	555	10,522,213	8,522,609	8,411,509	SG	26.023%	26.482%	2,738,157	2,256,921	2,227,500
10	Existing Firm Demand UPL	555	2,364,360	13,745,556	13,339,936	SG	26.023%	26.482%	615,269	3,640,040	3,532,625
11	Existing Firm Energy	555	32,904,819	48,266,029	47,550,895	SE	25.101%	25.369%	8,259,599	12,244,782	12,063,357
12	Post-merger Firm	555	627,875,283	593,272,567	639,269,405	SG	26.023%	26.482%	163,389,678	157,107,935	169,288,623
13	Secondary Purchases	555	-	-	-	SE	25.101%	25.369%	-	-	-
14	Other Generation Expense	555	-	-	-	SG	26.023%	26.482%	-	-	-
15	**Total Purchased Power**		673,666,674	663,806,761	708,571,746				175,002,703	175,249,678	187,112,106
16											
17	**Wheeling Expense**										
18	Existing Firm PPL	565	21,615,814	21,996,429	23,937,361	SG	26.023%	26.482%	5,625,004	5,825,001	6,338,991
19	Existing Firm UPL	565	-	-	-	SG	26.023%	26.482%	-	-	-
20	Post-merger Firm	565	114,818,653	110,442,896	116,657,475	SG	26.023%	26.482%	29,878,836	29,247,021	30,892,740
21	Non-Firm	565	2,694,259	15,162,218	16,543,742	SE	25.101%	25.369%	676,299	3,846,557	4,197,041
22	**Total Wheeling Expense**		139,128,726	147,601,542	157,138,579				36,180,139	38,918,580	41,428,772
23											
24	**Fuel Expense**										
25	Fuel Consumed - Coal	501	657,614,065	543,415,251	551,919,752	SE	25.101%	25.369%	165,070,915	137,860,962	140,018,500
26	Fuel Consumed - Coal (Cholla)	501	-	-	-	SE	25.101%	25.369%	-	-	-
27	Fuel Consumed - Gas	501	6,268,061	7,548,171	7,414,294	SE	25.101%	25.369%	1,573,376	1,914,923	1,880,959
28	Natural Gas Consumed	547	274,027,051	327,262,235	327,843,338	SE	25.101%	25.369%	68,784,867	83,024,329	83,171,751
29	Simple Cycle Comb. Turbines	547	3,234,523	4,308,331	4,421,288	SE	25.101%	25.369%	811,913	1,092,996	1,121,652
30	Steam from Other Sources	503	4,508,022	3,966,594	3,966,594	SE	25.101%	25.369%	1,131,580	1,006,299	1,006,299
31	**Total Fuel Expense**		945,651,721	886,500,582	895,565,265				237,372,653	224,899,509	227,199,161
32											
33	TAM Settlement Adjustment**		(8,802,107)	-	-		As Settled		(2,250,000)	-	-
34											
35	**Net Power Cost (Per GRID)**		1,400,378,595	1,445,454,540	1,438,997,542				355,417,177	372,213,874	370,395,728
36											
37	Oregon Situs NPC Adustments		1,102,774	(1,645,063)	(158,854)	OR	100.000%	100.000%	1,102,774	(1,645,063)	(158,854)
38	**Total NPC Net of Adjustments**		1,401,481,369	1,443,809,477	1,438,838,689				356,519,952	370,568,810	370,236,874
39											
40	Production Tax Credit (PTC)		(217,892,375)	(250,144,103)	(258,284,914)	SG	26.023%	26.482%	(56,701,332)	(66,242,104)	(68,397,920)
41	**Total TAM Net of Adjustments**		1,183,588,994	1,193,665,374	1,180,553,775				299,818,620	304,326,706	301,838,955
42											
43									Increase Absent Load Change	4,508,086	2,020,335
44											
45								Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-375	$299,818,620		
46								$ Change due to load variance from UE-375 forecast	3,293,946		
47								2022 Recovery of NPC (incl. PTC) in Rates	$303,112,566		
48											
49	*TAM Settlement UE 375 - Agreed to decrease Oregon-allocated NPC by $2,250,000								**Increase Including Load Change**	**$ 1,214,140**	**$ (1,273,612)**
50											
51									Add Other Revenue Change	-	2,986,282
52											
53									**Total TAM Increase/(Decrease)**	**$ 1,214,140**	**$ 1,712,670**

Docket No. UE 390
Exhibit PAC/402
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Douglas R. Staples

2022 Results of Updated Net Power Cost Study Reply Filing

July 2021

PacifiCorp

Final July TAM Update

Net Power Cost Analysis

12 months ended December 2022

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	01/22-12/22	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,568,265	735,563	524,156	474,513	458,319	416,063	587,880	738,792	739,513	721,285	723,802	714,556	733,822
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	7,453	623	623	623	623	623	623	623	623	623	623	623	603
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	117,580	8,068	7,601	9,462	4,912	3,927	6,910	17,829	20,473	14,692	8,897	6,870	7,937
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,693,299	744,254	532,379	484,597	463,855	420,613	595,414	757,244	760,610	736,600	733,322	722,049	742,362
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	21,253,470	5,225,320	4,692,960	5,187,720	2,031,500	2,084,470	2,031,500	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	21,253,470	5,225,320	4,692,960	5,187,720	2,031,500	2,084,470	2,031,500	-	-	-	-	-	-
System Balancing Sales													
COB	40,367,476	3,901,602	2,560,762	2,225,842	1,345,523	1,493,933	2,862,691	3,426,480	4,468,542	3,837,433	4,937,491	4,898,741	4,408,436
Four Corners	65,236,537	5,928,430	5,292,027	1,973,296	2,451,094	1,471,242	4,546,940	8,732,336	8,122,451	7,548,343	6,876,889	6,677,459	5,616,032
Mead	30,800,379	5,018,124	3,503,082	2,024,381	895,966	333,520	1,587,306	3,534,132	3,927,995	3,420,439	2,603,461	2,044,460	1,907,514
Mid Columbia	46,470,211	3,350,055	1,125,593	356,899	1,629,975	328,545	1,764,374	9,232,034	10,387,977	6,970,327	4,158,558	2,971,507	4,194,366
Mona	32,120,066	4,270,891	1,842,031	571,379	621,309	277,682	2,113,863	2,915,204	3,424,963	7,861,571	3,361,676	2,962,101	1,897,396
NOB	6,702,906	-	597,865	540,887	364,346	462,924	121,713	924,821	1,881,589	814,628	28,986	-	965,147
Palo Verde	71,631,443	7,913,579	4,695,637	8,191,855	2,909,730	2,798,571	5,354,295	12,703,059	13,502,826	8,771,056	4,569,903	165,088	55,843
Trapped Energy	2,260	2,190	70	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	293,331,278	30,384,870	19,617,067	15,884,539	10,217,943	7,166,416	18,351,183	41,468,065	45,716,342	39,223,798	26,536,964	19,719,357	19,044,734
Total Special Sales For Resale	322,278,047	36,354,444	24,842,406	21,556,857	12,713,297	9,671,500	20,978,097	42,225,309	46,476,952	39,960,397	27,270,287	20,441,406	19,787,096

PacifiCorp

Final July TAM Update

Net Power Cost Analysis

12 months ended December 2022

Purchased Power & Net Interchange

	01/22-12/22	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Long Term Firm Purchases													
Appaloosa 1A Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Appaloosa 1B Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Castle Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,503,295	382,039	462,911	561,303	561,021	477,253	410,331	463,102	388,216	366,716	381,506	467,770	581,128
Cove Mountain Solar	3,863,173	184,607	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,128
Cove Mountain Solar II	9,546,217	458,099	481,285	838,933	913,284	1,051,185	1,130,513	1,096,629	1,037,640	889,811	716,297	511,782	420,758
Deseret Purchase	34,204,388	2,852,152	2,845,453	2,732,909	2,631,083	2,548,015	2,657,879	3,059,823	3,059,823	3,027,668	3,039,726	2,813,298	2,936,560
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	475,009	176,342	157,638	141,029	-	-	-	-	-	-	-	-	-
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Graphite Solar	6,310,360	315,660	357,582	564,720	619,747	695,093	713,257	695,674	650,775	583,233	486,296	359,441	268,882
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Horseshoe Solar	2,667,232	-	-	-	-	-	21,926	649,761	615,683	512,127	411,472	254,320	201,944
Hunter Solar	7,120,458	373,103	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,550
Hurricane Purchase	165,035	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,345
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	4,439,070	372,930	368,920	372,930	376,940	376,940	376,940	372,930	372,930	344,860	364,910	372,930	364,910
Milican Solar	2,735,535	70,656	142,907	211,909	266,728	316,578	344,588	388,056	342,899	275,962	180,695	115,734	78,823
Milford Solar	7,078,933	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	393,922	308,528
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,855,952	84,387	94,943	140,787	177,207	210,326	228,936	257,815	227,812	183,342	120,049	76,891	53,456
Rock River Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rocket Solar	2,835,362	-	-	-	-	-	23,391	722,941	654,156	549,984	418,234	255,513	211,145
Sigurd Solar	5,975,468	311,168	349,111	514,891	562,169	646,129	710,144	660,236	605,234	565,052	458,516	322,228	270,590
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,662,796	2,790,663	1,806,921	2,135,557	1,618,738	1,425,615	1,202,984	807,052	950,561	1,186,424	1,734,559	2,352,376	2,651,346
Top of the World Wind	40,686,138	5,436,527	3,612,759	4,244,151	3,270,658	2,907,364	2,399,806	1,720,417	1,872,120	2,296,841	3,513,203	4,491,632	4,920,662
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,383,110	769,734	899,379	1,146,384	1,053,092	797,120	854,930	677,617	645,569	761,818	837,862	974,504	965,102
UT Solar Adjustment	(16,666,690)	(414,201)	(477,740)	(1,042,097)	(1,171,607)	(1,386,720)	(1,435,264)	(2,716,268)	(2,504,068)	(2,084,147)	(1,671,741)	(1,020,665)	(742,172)
Long Term Firm Purchases Total	199,488,904	19,328,474	16,493,932	18,407,800	16,821,893	15,951,364	15,476,140	14,544,527	14,234,876	15,043,970	16,741,136	17,664,091	18,780,702
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

PacifiCorp

Final July TAM Update

Net Power Cost Analysis

12 months ended December 2022	01/22-12/22	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Qualifying Facilities													
QF California	1,895,406	162,633	172,651	205,751	212,594	193,211	159,233	134,854	130,374	123,448	127,844	126,171	146,640
QF Idaho	6,561,844	521,703	485,716	524,279	458,424	493,016	619,964	651,887	580,321	531,343	553,545	526,929	614,717
QF Oregon	49,399,870	2,767,509	2,985,364	3,999,426	5,027,644	5,387,968	5,691,881	5,580,713	5,334,307	4,531,951	3,459,567	2,367,692	2,265,849
QF Utah	12,408,937	848,618	885,366	1,056,273	1,100,403	1,208,104	1,228,948	1,145,332	1,137,818	1,069,438	1,017,171	896,403	815,062
QF Washington	214,001	-	-	-	5,769	20,936	50,654	56,972	52,342	25,045	2,284	-	-
QF Wyoming	86,270	10,075	8,452	10,106	6,275	5,030	3,054	8,330	7,517	4,210	5,954	6,819	10,449
Biomass One QF	15,614,593	1,267,642	1,228,421	1,357,350	1,636,955	1,044,080	1,026,284	1,488,106	1,433,188	1,421,889	1,486,118	1,457,169	767,392
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	181,350	2,306	7,463	3,425	3,532	3,739	7,210	37,087	41,328	40,379	18,076	8,973	7,832
Enterprise Solar I QF	12,473,865	611,340	752,602	974,573	1,106,815	1,245,131	1,370,394	1,537,557	1,507,789	1,173,477	949,861	701,600	542,727
Escalante Solar I QF	11,515,430	561,065	680,346	877,315	1,006,345	1,178,752	1,294,854	1,422,267	1,392,895	1,088,207	869,085	638,954	505,344
Escalante Solar II QF	10,840,674	527,342	638,583	826,601	946,673	1,115,326	1,224,571	1,345,889	1,306,789	1,025,478	814,388	597,862	471,171
Escalante Solar III QF	10,442,698	513,699	623,725	800,706	921,256	1,088,119	1,195,182	1,307,177	1,270,302	996,975	745,740	547,944	431,874
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,693,307	533,253	875,763	777,746	820,996	506,256	552,652	642,720	619,325	779,838	765,907	901,916	916,935
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,835,774	544,536	614,654	890,473	982,087	1,146,476	1,246,724	1,326,384	1,264,408	972,504	804,390	577,936	465,202
Granite Mountain West Solar QF	7,172,267	360,727	406,976	590,987	651,525	758,979	823,975	877,723	835,347	644,272	532,107	381,598	308,051
Iron Springs Solar QF	11,121,950	629,316	662,149	891,964	1,009,338	1,120,393	1,271,634	1,333,691	1,321,374	1,000,417	810,606	574,043	497,025
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,442	1,007,478	917,570	1,126,955	897,120	856,897	745,979	668,253	572,323	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,905,879	1,392,508	1,039,745	867,285	684,928	476,623	503,274	411,828	442,266	469,755	671,689	911,019	1,034,959
Mountain Wind 2 QF	13,899,125	2,030,291	1,559,123	1,351,134	1,069,087	746,021	905,871	764,010	737,182	777,975	1,008,414	1,412,658	1,537,361
North Point Wind QF	19,444,476	1,119,817	1,887,393	1,734,776	1,844,679	1,128,968	1,254,304	1,494,039	1,533,687	1,852,541	1,780,259	1,917,468	1,896,546
Oregon Wind Farm QF	12,470,313	721,155	966,803	1,118,155	1,283,514	1,266,915	1,218,352	1,255,449	1,120,480	935,736	749,587	788,767	1,045,402
Pavant II Solar QF	4,959,080	201,315	257,063	378,853	435,113	513,729	569,251	656,296	656,880	489,779	363,926	241,028	195,849
Pioneer Wind Park I QF	10,649,365	1,304,319	924,970	1,187,417	905,678	708,589	651,185	653,415	683,216	455,095	819,798	1,259,137	1,096,547
Power County North Wind QF	5,647,194	431,651	569,790	542,537	530,314	367,152	360,809	373,188	380,639	393,029	530,965	541,512	625,608
Power County South Wind QF	5,029,309	381,165	501,482	489,271	492,038	316,908	320,949	329,324	354,756	347,971	464,720	488,211	542,514
Roseburg Dillard QF	1,004,727	44,544	51,457	27,164	104,964	107,167	90,090	165,876	136,493	67,667	77,977	77,698	53,631
Sage I Solar QF	2,256,857	80,192	79,413	189,005	204,759	233,577	261,123	333,738	333,817	207,287	154,769	104,237	74,940
Sage II Solar QF	2,259,283	80,277	79,507	189,206	204,979	233,788	261,418	334,095	334,187	207,522	154,927	104,366	75,010
Sage III Solar QF	1,859,270	67,598	66,161	156,107	166,890	191,458	213,576	272,357	272,200	171,079	129,834	88,345	63,665
Spanish Fork Wind 2 QF	2,778,082	219,288	178,796	202,762	161,385	155,649	216,228	294,704	317,649	274,406	243,899	252,418	260,899
Sunnyside QF	30,732,217	2,358,217	2,207,189	2,528,442	2,068,107	2,776,639	2,790,251	2,806,797	2,767,405	2,627,199	2,412,417	2,803,191	2,586,363
Sweetwater Solar QF	7,734,664	257,166	371,747	562,483	683,975	807,847	977,678	1,106,980	1,036,166	809,400	623,027	297,691	200,503
Tesoro QF	361,892	55,140	40,773	32,666	22,840	33,103	8,974	17,028	27,413	24,575	23,647	23,979	51,752
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,416,119	410,321	476,104	625,734	829,197	852,526	905,095	1,035,085	1,006,568	792,565	668,252	442,169	372,504
Utah Pavant Solar QF	6,436,976	239,669	277,573	474,672	558,189	659,215	736,618	874,649	828,307	689,619	508,949	323,716	265,801
Utah Red Hills Solar QF	11,525,396	482,179	617,715	785,433	1,029,774	1,197,359	1,233,964	1,521,325	1,477,835	1,324,028	807,057	585,413	463,314
Qualifying Facilities Total	335,502,902	22,746,051	24,098,607	28,357,031	30,074,157	30,145,647	31,992,203	34,265,127	33,254,889	28,962,786	25,956,007	23,684,723	21,965,675

PacifiCorp

Final July TAM Update

Net Power Cost Analysis

12 months ended December 2022	**01/22-12/22**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(962,821)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,118,783	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,155,962	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330
Total Long Term Firm Purchases	536,147,768	42,170,856	40,688,869	46,861,161	46,992,379	46,193,341	47,564,673	48,905,985	47,586,095	44,103,086	42,793,473	41,445,144	40,842,707
Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	4,500,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	-	-
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	4,500,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	-	-
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	20,140,300	1,035,000	993,600	1,117,800	-	-	-	4,827,500	5,213,700	4,827,500	717,600	690,000	717,600
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	9,012,600	3,097,980	2,805,840	3,108,780	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	29,152,900	4,132,980	3,799,440	4,226,580	-	-	-	4,827,500	5,213,700	4,827,500	717,600	690,000	717,600

PacifiCorp

Final July TAM Update

Net Power Cost Analysis

12 months ended December 2022	01/22-12/22	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
System Balancing Purchases													
COB	16,832,049	982,901	1,718,522	2,341,545	431,262	757,651	1,520,590	3,027,097	2,809,965	1,300,820	644,917	578,695	718,083
Four Corners	28,201,408	2,585,658	7,226,593	4,071,151	1,540,190	3,391,313	1,456,285	2,009,160	1,011,707	856,926	677,537	865,849	2,509,039
Mead	8,144,659	847,923	848,671	498,181	366,062	153,972	601,013	1,123,789	448,233	800,874	786,912	842,539	826,491
Mid Columbia	114,420,013	6,394,648	1,211,026	404,169	4,818,403	11,915,517	16,386,968	22,672,156	25,446,119	7,408,842	4,790,300	3,146,635	9,825,230
Mona	12,273,845	1,816,785	1,015,758	207,968	303,543	488,753	633,737	708,261	916,930	1,479,625	1,487,970	1,857,709	1,356,807
NOB	12,641,450	-	654,071	906,669	605,186	1,145,171	340,394	1,967,712	3,882,160	1,377,782	85,679	-	1,676,626
Palo Verde	2,045,338	471,441	386,019	652,661	193,751	-	-	-	-	6,170	279,174	12,524	43,597
EIM Imports/Exports	(61,676,929)	(3,628,009)	(3,249,467)	(4,649,317)	(4,946,288)	(5,215,764)	(3,411,978)	(9,968,223)	(10,865,614)	(5,954,596)	(3,202,701)	(3,166,781)	(3,418,193)
Emergency Purchases	5,889,245	-	-	-	91,150	1,861,588	442,396	2,159,810	167,923	979,767	138,277	-	48,332
Total System Balancing Purchases	138,771,078	9,471,347	9,811,192	4,433,027	3,403,260	14,498,200	17,969,406	23,699,762	23,817,425	8,256,211	5,688,065	4,137,170	13,586,012
Total Purchased Power & Net Interchange	708,571,746	56,225,183	54,749,501	55,970,768	50,845,639	61,141,541	65,984,079	77,883,247	77,067,221	57,636,797	49,649,139	46,272,314	55,146,318
Wheeling & U. of F. Expense													
Firm Wheeling	154,798,692	13,007,217	12,805,980	13,083,529	12,824,654	11,889,628	12,740,622	13,378,724	13,462,900	12,485,378	12,945,466	12,740,088	13,434,507
C&T EIM Admin fee	2,246,990	184,546	167,911	161,471	204,085	222,363	208,177	197,624	189,924	182,991	165,631	184,972	177,294
ST Firm & Non-Firm	92,897	9,614	3,133	2,374	418	12	1,338	5,503	3,711	2,156	8,099	24,218	32,321
Total Wheeling & U. of F. Expense	157,138,579	13,201,377	12,977,025	13,247,374	13,029,157	12,112,003	12,950,137	13,581,850	13,656,535	12,670,525	13,119,196	12,949,278	13,644,122
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	14,510,872	2,000,659	1,624,684	16,264	1,504,838	-	240,055	1,711,916	1,811,824	1,631,015	1,185,727	1,180,684	1,603,207
Craig	18,341,900	1,958,710	1,705,362	1,870,716	1,507,795	739,280	1,518,028	1,663,866	1,895,984	1,776,772	1,792,364	863,632	1,049,392
Dave Johnston	62,960,748	6,091,462	5,707,126	5,315,648	4,472,510	4,939,943	4,731,563	5,189,558	5,696,197	5,128,033	5,687,324	4,482,260	5,519,123
Hayden	11,673,559	1,155,412	1,000,539	1,067,833	969,754	1,189,341	1,094,929	1,146,800	963,895	650,212	828,728	799,975	806,141
Hunter	117,552,134	13,627,170	10,494,642	10,176,198	4,617,005	7,452,135	8,254,184	10,396,991	10,362,045	9,421,833	8,692,982	11,850,921	12,206,028
Huntington	96,389,879	11,328,086	8,684,341	8,778,575	5,980,506	6,282,906	6,053,837	8,992,674	9,314,387	6,221,118	5,218,652	7,854,260	11,680,537
Jim Bridger	180,623,179	12,594,214	13,157,212	14,628,037	14,342,583	-	7,692,692	24,356,945	23,874,789	19,642,116	17,755,073	17,291,587	15,287,931
Naughton	25,762,241	3,115,840	2,216,767	2,242,900	1,653,666	1,586,449	1,824,572	2,479,832	2,399,836	2,062,121	2,069,378	1,743,415	2,367,464
Wyodak	24,105,241	1,761,733	1,697,346	2,331,177	2,039,899	2,526,766	2,261,374	2,403,114	2,234,295	2,146,500	1,991,753	1,588,153	1,123,131
Total Coal Fuel Burn Expense	551,919,752	53,633,287	46,288,019	46,427,346	37,088,557	24,716,821	33,671,233	58,341,695	58,553,252	48,679,720	45,221,981	47,654,886	51,642,954

PacifiCorp

Final July TAM Update

Net Power Cost Analysis

12 months ended December 2022	01/22-12/22	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Gas Fuel Burn Expense													
Chehalis	55,012,877	6,929,808	5,242,044	5,390,332	2,762,180	2,096,519	2,399,179	4,794,904	4,797,603	4,598,620	5,585,027	5,060,132	5,356,528
Currant Creek	51,515,590	5,213,274	3,770,340	2,093,913	2,972,365	2,521,476	4,680,942	5,965,453	4,403,432	4,946,406	5,117,183	5,271,249	4,559,558
Gadsby	6,701,287	585,906	284,019	86,090	252,796	96,751	505,158	1,041,110	982,221	720,777	513,461	573,580	1,059,416
Gadsby CT	3,854,661	397,272	114,881	24,302	131,917	21,929	165,924	603,403	494,120	401,425	443,096	346,469	709,922
Hermiston	23,273,261	2,453,026	2,383,957	2,676,753	897,052	9,213	658,519	2,249,769	2,285,108	2,344,987	2,401,564	2,460,778	2,452,535
Lake Side 1	67,665,942	6,698,784	5,296,370	3,755,126	4,907,964	3,348,213	5,691,162	7,055,955	6,969,377	6,555,358	5,752,651	5,770,696	5,864,286
Lake Side 2	64,575,599	7,339,238	5,659,788	4,423,841	4,866,378	3,099,532	5,248,392	5,490,926	5,807,194	5,413,789	5,047,505	5,583,780	6,595,236
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	25,095,442	2,377,719	1,987,535	2,099,937	1,251,455	2,802,175	2,910,176	2,178,719	1,932,167	1,351,783	1,628,226	1,630,323	2,945,225
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	297,694,659	31,995,028	24,738,934	20,550,295	18,042,107	13,995,807	22,259,453	29,380,238	27,671,223	26,333,146	26,488,714	26,697,008	29,542,706
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	5,244,205	(2,254,940)	(1,356,320)	484,065	1,469,550	1,609,210	1,409,550	537,695	763,670	532,350	2,294,543	770,625	(1,015,793)
Clay Basin Gas Storage	(79,834)	(152,788)	(118,347)	(7,476)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(37,432)	(129,487)
Pipeline Reservation Fees	36,819,890	3,091,445	2,957,223	3,062,318	3,041,237	3,063,477	3,050,346	3,116,887	3,112,651	3,061,798	3,097,541	3,053,929	3,111,037
Total Gas Fuel Burn Expense	339,678,920	32,678,745	26,221,490	24,089,201	22,605,137	18,720,736	26,771,592	33,087,063	31,599,786	29,979,536	31,933,039	30,484,131	31,508,463
Other Generation													
Blundell	3,966,594	402,864	363,877	363,877	354,445	368,588	340,534	321,970	337,762	357,746	344,106	197,118	213,705
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-												
Dunlap I Wind	-												
Ekola Flats Wind	-												
Foote Creek I Wind	-												
Glenrock Wind	-												
Glenrock III Wind	-												
Goodnoe Wind	-												
High Plains Wind	-												
Leaning Juniper 1	-												
Marengo I Wind	-												
Marengo II Wind	-												
McFadden Ridge Wind	-												
Pryor Mountain Wind	-												
Rolling Hills Wind	-												
Seven Mile Wind	-												
Seven Mile II Wind	-												
Black Cap Solar													
TB Flats Wind													
TB Flats Wind II													
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	3,966,594	402,864	363,877	363,877	354,445	368,588	340,534	321,970	337,762	357,746	344,106	197,118	213,705
Net Power Cost	**1,438,997,542**	119,787,012	115,757,507	118,541,710	111,209,638	107,388,189	118,739,478	140,990,515	134,737,604	109,363,926	112,997,175	117,116,323	132,368,467

Docket No. UE 390
Exhibit PAC/403
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Douglas R. Staples

2022 Updates Summary Reply Filing

July 2021

Oregon TAM 2022 (Initial Filing)	NPC ($) =	1,445,454,540
	$/MWh =	23.87

	Impact ($) Oregon Allocated Basis	NPC ($) Total Company
Corrections		
Market Caps	7,389	
Updates		
U01 - Official Forward Price Curve	3,036,627	
U02 - Short-Term Firm Transactions, Gas Swaps	432,617	
U03 - Long Term Contracts and QFs	(315,216)	
U04 - Coal Cost	1,506,420	
U05 - Wheeling	2,468,595	
U06 - EIM	(1,076,679)	
Total Changes =	6,059,753	
Total Change from Initial Filing		(6,456,998)
Oregon TAM 2022 (Reply Filing)	**NPC ($) =**	**1,438,997,542**
	$/MWh =	**23.76**

REDACTED
Docket No. UE 390
Exhibit PAC/500
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Seth Schwartz

July 2021

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. IDENTIFICATION OF WITNESS AND QUALIFICATIONS

Q. Please state your name, business address, and present position.

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209. My position is President, Energy Ventures Analysis, Inc. (EVA).

Q. On whose behalf are you submitting reply testimony?

A. I am an independent expert PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) has retained to testify on the issues raised in this case, including the costs used for economic dispatch of generating units and prudent practices for contracting for coal supplies.

Q. Describe your education and professional experience.

A. I am the President of EVA and have been a principal since its founding in 1981. EVA performs market analysis and management consulting for the United States (U.S.) energy markets. We cover markets for coal, natural gas, oil and electric power. Our clients are participants in the energy market, including producers, consumers, transporters, investors and regulators. In addition to my corporate responsibilities, I manage our coal consulting practice, including market studies, publications and management consulting. Our market studies include analyses of coal supply, demand and prices. Our consulting projects include management audits of fuel procurement practices by electric power companies, both regulated and unregulated. Our management audits have included projects for regulatory agencies, interveners and company management. I have testified as an expert witness on energy markets and fuel procurement practices in front of numerous state public utility commissions as well as the Federal Energy Regulatory Commission (FERC). My current resume is attached as Exhibit PAC/501. I have a Bachelor of Science in Geological Engineering degree from Princeton University.

Q. Have you testified in previous regulatory proceedings?

A. Yes. This experience includes numerous expert reports and testimony on behalf of the Public Utility Commission of Ohio regarding the fuel procurement practices of utilities regulated in that state, including Dayton Power & Light, Cincinnati Gas & Electric, Ohio Power, Columbus Southern Power, Cleveland Electric, Ohio Edison and Monongahela Power. I testified on behalf of utility commissions, intervenors and regulated utilities regarding the prudence of fuel procurement in the states of Florida, Georgia, Louisiana, Pennsylvania and Texas, as well as FERC.

Q. Have you previously testified regarding the coal mining operations and coal procurement practices of PacifiCorp?

A. Yes. In 1991, following the merger of Utah Power & Light and PacifiCorp, I directed a study of the coal supply operations and fuel procurement practices of PacifiCorp on behalf of the seven state[1] public service commissions and FERC, as well as a subsequent update in 1995. These studies were comprehensive reviews of the management of the mining operations and coal supply plan for all of PacifiCorp's coal-fired generation facilities. In 2011, I also testified on behalf of the Utah Office of Consumer Services in Docket No. 10-035-124 regarding PacifiCorp's fuel supply management and coal supply operations. I have also testified on behalf of PacifiCorp in the states of Oregon, California, Idaho, Utah, Washington, and Wyoming.

[1] Oregon, California, Idaho, Montana, Utah, Washington, and Wyoming.

Q. Please identify the cases in which you have previously testified before the Public Utility Commission of Oregon (Commission) regarding the coal mining operations and coal procurement practices of PacifiCorp.

A. In 2015, I filed testimony on behalf of PacifiCorp in docket UM 1712. In 2017, I filed testimony on behalf of PacifiCorp in docket UE 323. In 2020, I filed testimony on behalf of PacifiCorp in docket UE 375.

Q. What was the subject of your 2015 testimony in docket UM 1712?

A. The subject of my testimony was the prudence of PacifiCorp's decision to close the Deer Creek coal mine and the need to enter into a long-term coal supply agreement for the Huntington plant to replace this coal supply.

Q. Did any parties to docket UM 1712 question the prudence of the Company entering into a long-term coal supply agreement for the Huntington Plant?

A. Yes. Testimony was filed by Commission Staff, the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities (now known as Alliance of Western Energy Consumers or AWEC), and Sierra Club. All of these parties filed testimony asserting that the Company was taking a risk by entering into a long-term commitment with a minimum "take-or-pay" provision. My testimony addressed the need for a long-term coal supply agreement due to the limited coal supply options in the Utah coal market.

Q. What was the subject of your 2017 testimony in docket UE 323?

A. The subject of my testimony was regarding the structure of coal markets in the U.S. in general and for PacifiCorp's power plants in particular, the role of multi-year coal contracts in supplying reliable and economic fuel for plant operations, and the function of take-or-pay and liquidated damage provisions in long-term coal supply contracts.

Q. Did any parties to docket UE 323 question the prudence of the Company's coal procurement decisions?

A. Yes. Testimony was filed by Commission Staff and Sierra Club raising various issues related to PacifiCorp's coal supply agreements (CSAs) and coal procurement strategies. Staff proposed specific adjustments related to economic cycling of coal plants and liquidated damages under the Cholla coal supply agreement, while Sierra Club proposed a specific adjustment related to the Naughton plant. The Company's plan to enter into a new contract to supply the Jim Bridger plant with Black Butte Coal Company to replace an expiring contract was also at issue. The CSAs reviewed in the case contained minimum take provisions. As described in more detail in Mr. Dana M. Ralston's reply testimony, the Commission declined to impose any adjustments related to PacifiCorp's forecasted coal plant dispatch, finding that the Company's Generation and Regulation Initiative Decision Tools (GRID) modeling reflected historical, normalized practices, but several workshops were held with parties including a coal workshop.[2]

Q. What was the subject of your 2020 testimony in docket UE 375?

A. The subject of my testimony was regarding the structure of coal markets in the U.S. in general and for PacifiCorp's power plants in particular, the need for multi-year coal contracts in supplying reliable and economic fuel for plant operations, the need for minimum-volume commitments in coal supply contracts, and the purpose of take-or-

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[2] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order. No. 17-444 at 10-11.

pay and liquidated damage provisions. Also, I testified as to standard utility practice in using incremental cost of generation in dispatching power plants rather than the average cost.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the staff testimony of Mr. John Fox and Ms. Rose Anderson as well as the testimony of Mr. Ed Burgess, filed on behalf of Sierra Club, challenging PacifiCorp's coal fuel expenditures.

Q. Please summarize your testimony.

A. My testimony:

- Explains that the primary purpose of purchasing coal is to support the reliability of the Company's power supply by ensuring that there is sufficient fuel to operate its coal-fired power plants when needed to serve ratepayer load;
- Predicts that this year 2021 will be a severe test of the reliability of the power supply system in Oregon and the Pacific Northwest due to a very low water year, demonstrating the need for its coal-fired power plants to have adequate fuel supply;
- Describes the structure of the coal markets in general and the need for multi-year CSAs to provide reliable and economic fuel supply for power plants located in areas with relatively illiquid coal markets;
- Supports the need for minimum volume provisions in multi-year CSAs in order to secure adequate coal supply and the use of take-or-pay and liquidated damage provisions;

- Disputes the assertion by Mr. Burgess as to the variable costs of the Bridger Coal Company (BCC) mine;
- Rebuts Staff testimony that the Commission should decide to reduce the amount that the Company can recover in the 2022 Transition Adjustment Mechanism (TAM) based on the minimum volume provisions in a Huntington coal supply contract signed in 2014 to support the closure of the Deer Creek mine;
- Refutes the recommendation by Mr. Burgess that utilities should avoid entering contracts where the minimum take provisions exceed 50 percent of projected consumption; and,
- Rejects the recommendation by Mr. Burgess that the Commission should deem the minimum take quantities in the new Hunter coal contracts to be imprudent.

III. THE ROLE OF COAL PROCUREMENT IN PROVIDING RELIABLE POWER SUPPLY

Q. What is the primary objective in the fuel procurement practices of an electric utility?

A. The first objective is to make sure that the utility's power plants have sufficient fuel to operate at peak output for an extended period to supply reliable power to the utility's customers.

Q. How are fossil-fuel power plants important in a utility's ability to provide reliable power supply?

A. The electric power system must be operated so that power supply and demand are closely matched to avoid dangerous voltage fluctuations. Demand for electricity varies constantly, so power supply must be constantly adjusted to match demand. Fossil-fuel power plants (fueled by coal, natural gas, or oil) are currently the only sources of generation that can be ramped up to increase generation at the option of the utility. They are known traditionally as “dispatchable” power plants because they can be operated (“dispatched”) whenever needed by the utility (within limits of startup and ramping time). Output from wind and solar power plants fluctuates with the availability of the resource (solar only operates when it is sunny and wind only when it is windy) and can only be “dispatched” downward. Generation from wind and solar power has zero variable costs, so utilities operate these plants whenever available, but utilities cannot choose to ramp up output from wind and solar power when needed to meet demand. Hydroelectric power can be dispatched by the utility to the extent there is adequate reservoir storage (within stream flow limits). The increasing share of power supply from new wind and solar plants has increased the necessity of dispatchable fossil fuel power plants to ramp up and down to both meet varying load and to accommodate the growth of wind and solar power supply.

Q. Why do fossil-fuel power plants need to be able to operate at peak output for an extended period?

A. PacifiCorp is part of the Pacific Northwest (PNW) regional power system. The primary source of power in the PNW region is hydroelectric power, primarily the dams on the Federal Columbia River System operated by Bonneville Power Administration (BPA). The BPA provides an annual assessment of the loads and resources for the PNW region (the “White Book”).[3] In an average water year, hydro will provide 15,130 megawatts (MW), about 62 percent of regional energy load. However, BPA plans for the “critical water” year when stream flow is at its lowest

[3] Bonneville Power Administration, Pacific Northwest Loads and Resources Study, October 2020.

historical level (the year 1937). In a critical water year, PNW hydro generation falls to an average of 11,667 MW. In low water years, the thermal power plants (coal and natural gas) must be able to operate near maximum capacity for an extended period, perhaps all year.

Q. How do the coal plants of PacifiCorp support regional power reliability?

A. While hydro power provides the bulk of capacity and energy in the PNW region, new thermal power plants were developed to supply demand growth and support system reliability in low water years. Regional utilities, including PacifiCorp, developed coal-fired power plants near the coal fields ("mine-mouth" power plants) and transmission lines to provide system reliability.

Q. How were coal supplies developed to provide fuel to PacifiCorp's coal-fired power plants?

A. All of PacifiCorp's coal plants were originally developed as mine-mouth plants. Coal mines were built at the same time to be able to supply the annual maximum power output at these plants (including the Naughton, Jim Bridger, Dave Johnston and Wyodak plants in Wyoming, the Hunter and Huntington plants in Utah, the Hayden and Craig plants in Colorado, and the Colstrip plant in Montana).

Q. Are all of PacifiCorp's coal plants still mine-mouth plants?

A. No. As adjacent coal supplies depleted and western commercial coal markets expanded, it became more economic for PacifiCorp to transition the coal supply for some of its plants to purchase outside coal from commercial suppliers. This decision was based on the economics and availability of coal from outside sources compared to the original mine-mouth supply.

Q. Did the switch to commercial coal supply sources change the need for PacifiCorp to procure enough coal to support full load power generation?

A. No. Without sufficient coal available to support full load, the coal-fired power plants cannot be counted upon to support system reliability, especially in low water years.

Q. Does that mean that PacifiCorp must contract to purchase 100 percent of coal burn at maximum load in advance?

A. No. But it does mean that the coal supply for PacifiCorp's plants must be **capable** of supporting full generation. This capability can be supplied by a combination of mine production capacity (for mine-mouth supply), coal contracts (including volume flexibility to increase shipments to support high burn), spot purchases where the market is sufficiently liquid for the coal to be available, and on-site coal inventories to provide security during supply interruptions.

Q. You mention "low water years". How does this affect coal procurement planning?

A. The importance of hydro power in the PNW region and its variability make it essential that PacifiCorp have enough coal supply capability to support high output from its power plants. During a low water year, these plants will be called upon to operate at high capacity factors for an extended period, perhaps all year.

Q. Are low water years predictable in advance?

A. No, but we are in a very low water year in the PNW and across the West in 2021. Stream flows on the Columbia River system are near record lows and water reservoirs on the Colorado River and in California are at extremely low levels. It is highly likely that hydro power generation in the PNW and across the Western power grid will be at the lowest level in 2021 in at least the last 50 years.

Q. What does this mean for power supply and system reliability?

A. Power markets already reflect the impact of low expected hydro generation. Forward power markets for the summer months are at record highs in California, the Desert Southwest, and mid-Columbia (the regional power hub for the PNW). This means that thermal power resources (coal and natural gas) are being relied upon to operate at very high levels. System reliability is at risk of failure without reliable generation from the coal-fired plants, and this generation from coal-fired plants cannot be depended on if the plants do not have a reliable source of fuel.

Q. Has the lack of reliable fuel supply already caused power system failure during 2021 in the U.S.?

A. Yes. The Electric Reliability Council of Texas' power grid failed during a cold snap in February 2021. There were large blackouts over four days caused by insufficient power supply to meet a period of high demand. While there were many factors in the power shortage, the largest cause was inadequate natural gas supply to support thermal power generation. The power plant capacity was useless without adequate fuel to operate.

Q. Are you saying that it does not matter if the Company pays too much for fuel?

A. Of course not. PacifiCorp should, and does, minimize its cost of coal for power generation. However, the first priority is reliability of power supply and that means reliability of fuel supply. As a result, there may be times when PacifiCorp incurs costs to commit for coal to have the capability to meet full load that it does not need to burn during the year based on actual demand and the economics of other power supplies. That does not make the decision imprudent, as implied by the Staff and Sierra Club.

IV. COAL MARKETS IN THE U.S. AND THE ROLE OF LONG-TERM COAL SUPPLY CONTRACTS

Q. Please provide an overview of the structure of coal markets in the U.S.

A. In the U.S., coal is found in a number of separate geographic and geological regions. Geographically, coal is produced in varying quantities in 25 different states. Geologically, coal is found in many different coalbeds (or seams), created by different depositional environments. Coalbeds located in the same geographic area generally are known as coal basins. Coal quality, coal production costs and access to customers vary widely among different coal basins. Coal from different coal basins is generally not fungible and customers are not easily and quickly able to substitute coal from one basin for another.

Q. How does coal transportation affect the structure of the coal markets?

A. Coal is a bulk commodity where the transportation cost can be a large share of the delivered coal price. The large transportation cost contributes to the separation of coal basins into different markets, as it can be very expensive for customers to switch from one coal basin to another.

Q. How does coal quality affect the structure of the coal markets?

A. Coal quality can vary widely in heat content, impurities (such as ash, sulfur and moisture) and in combustion characteristics (such as ash fusion temperature and grindability). While coal quality tends to be similar in a coalbed across a coal basin, quality can be very different among different coal basins. As a result, it can be difficult for customers to switch supplies from one coal basin to another, without time and expense to modify facilities to use coal with different quality.

Q. How does the structure of coal markets affect the ability of customers to purchase coal?

A. Some coal basins are fairly large markets with multiple suppliers and mining operations. In these markets, coal supply can be fairly liquid which allows customers to purchase coal from multiple suppliers under shorter-term purchases while maintaining reliable supplies. Other coal basins have few producers, in some cases only one mining operation within hundreds of miles. These markets are highly illiquid, and customers must purchase coal under long-term contracts in order to have any reliability of supply.

Q. How does coal transportation affect the ability of customers to purchase coal on the "spot" market?

A. Most coal is delivered in large batches, primarily in trains or barges, which requires advance contracting for timely and economic coal deliveries. As a result, there is no "spot" market for coal as conventionally defined, which is a purchase for immediate delivery. In the coal market, a spot purchase is normally considered to be a one-time purchase of coal for delivery in the following month or delivery for up to one year in the future.

Q. How does the structure of the coal markets differ from natural gas and power markets?

A. Both natural gas and power are fungible commodities—the quality is the same for all sources and supply can be substituted among different sources. These products are commingled during delivery and the product is not identified to any particular source (gas well or power plant). Further, these commodities are delivered continuously through pipelines or power lines. The combination of these factors allows for a liquid market which can be traded financially, separate from physical delivery. These features allow for hedging future market prices with financial products and for the purchase of the physical product under short-term contracts and spot purchases. In contrast, coal markets have little or no financial hedging capability and all purchases are under contracts for physical delivery.

Q. What is the typical strategy for coal purchasing employed by electric utilities?

A. Coal procurement strategies vary based upon the characteristics of the coal markets that are the most economic supply to the power plant. In the more liquid coal markets (with many competing coal producers), electric utilities typically purchase most of their coal under contracts with a term of one-three year duration. In these markets, utilities typically use a portfolio of coal contracts to commit to a minimum level of purchases starting at 70 percent—95 percent of expected burn in the first year. Spot purchases made during the calendar year typically fill in for variations in coal burn above the minimum burn expectations.

Q. How are utility coal purchasing strategies different in markets with less liquidity?

A. In coal markets where there are only a few, or even just one, producer, utilities cannot rely on short-term contracts or spot purchases to provide reliable and economic coal supplies. Both the consumer and the producer require longer-term contracts to support the investment of hundreds of millions of dollars in power plants or coal mines. In an illiquid market, because there are few coal options, a utility requires a longer-term contract both to induce the supplier to invest in the mining operation and to protect against paying prices far in excess of what would be charged in a competitive spot market. In turn, the coal supplier in an illiquid market requires a longer-term contract to have an assured market for the coal at a price which is above production costs.

Q. **Why do coal supply contracts have "minimum take" provisions?**

A. Without a commitment by the customer to purchase a minimum amount of coal, the coal supplier does not have an assured market for the output of the mine; the contract is merely an option for the customer to purchase coal if desired while paying no cost for this option. No coal producer could afford to agree to such a contract as it would require a large investment of capital in reserves, development and equipment to be available to supply coal with no assurance that any coal would be purchased. Further, coal suppliers (and similarly coal transporters) require a commitment to purchase at a regular rate ("ratable take") to employ and maintain a workforce able to meet the customer's requirements. As a result, while some contracts may provide some flexibility for the customer to vary purchase requirements, all coal supply contracts have a minimum volume commitment to purchase coal.

Q. What is the purpose of a "liquidated damages" provision in a coal supply contract?

A. A liquidated damages provision is a clause which quantifies the damages which a customer pays for the failure to purchase the minimum volume of coal under a coal supply contract. Liquidated damages are an alternative to a "take-or-pay" provision which requires the customer to purchase the coal or pay for it anyway. Not all coal suppliers will agree to liquidated damage provisions instead of "take-or-pay" provisions for a number of reasons. Liquidated damages define in advance the amount of the damages, which is a fraction of the purchase price and typically less than the damages which the supplier might incur due to the failure of the buyer to take deliveries. As a result, a liquidated damages provision is a clause which is favorable for the customer, as it quantifies the damages for the failure to purchase coal and essentially provides the customer with an option to purchase less coal at a defined cost if that is the most economic course of action.

Q. How does the ability of the customer to vary contract purchases affect the contract price?

A. The ability to nominate a range of annual coal purchases under a longer-term contract has great value to a customer and great cost to a supplier. If a customer bargains for the right to reduce coal purchases far below the maximum coal supply obligation of the supplier, the customer gains the benefit to adjust purchase levels to a wide range of coal needs. This passes on the risk of variations in coal demand onto the supplier. The requirement to maintain the capacity to provide the maximum volume of coal which the customer can purchase under the contract, while allowing the customer to significantly reduce coal purchases, has a large cost to the supplier. The supplier must maintain the capacity (including the equipment and the workforce) to produce the maximum amount of coal, while the customer may order only the minimum amount. That event would increase the supplier's production cost significantly (especially in illiquid markets where the ability to sell the coal to other customers is limited or non-existent). As a result, the supplier would insist on a much higher contract price to compensate for the risk of the customer reducing purchases in any year.

Q. How do utilities determine the fuel cost for economic dispatch when they have coal supply and transportation contracts with liquidated damages and projected burn falls below the minimum take obligation?

A. Utilities do not include the fixed cost of liquidated damages in determining the variable cost for the dispatch of their power plants. Customers benefit from least-cost dispatch as utilities only include the variable cost of fuel in the decision whether to operate a power plant (just as utilities would not include the fixed cost of a pipeline contract for transportation of natural gas). If the power plant dispatches at the variable cost (subtracting the liquidated damages from the full contract coal price) but would not have dispatched at the full cost, the most economic decision is to dispatch the power plant even though the fuel cost charged to the customer is greater than the fuel cost used for dispatch purposes. If a power plant still does not dispatch economically after subtracting the cost of liquidated damages, then the least-cost decision is to reduce plant operations and pay the liquidated damages.

Q. How does the ability to resell coal affect the least-cost decision?

A. In relatively liquid coal markets, a customer may be able to resell coal at a price below the contract price but above the variable cost after subtracting the cost of liquidated damages. In this case, the power plant should be dispatched at the market price for coal available for resale. However, in illiquid coal markets there is seldom a situation in which coal can be resold at a savings to customers because of the lack of secondary buyers in the area, transportation costs to an available market, or coal quality issues between markets.

V. FIXED AND VARIABLE COSTS AT BRIDGER COAL COMPANY

Q. Mr. Burgess opines that "at least [redacted] of the BCC coal costs are variable and could therefore be avoided if BCC coal consumption was ramped down".[4] What is the basis for his opinion?

A. Mr. Burgess asserts that this figure was "based PacifiCorp's own accounting."[5]

Q. Is that assertion correct?

A. No. Mr. Burgess has grossly mischaracterized the data response by PacifiCorp. The "accounting" calculation of variable costs was performed by Mr. Burgess, not PacifiCorp. Nowhere in the data response does PacifiCorp make any statement or calculation of the variable costs to operate the BCC mines. The Company only provided data for the "wholly identifiable fixed costs".[6] It was Mr. Burgess who calculated the BCC "variable" costs, by subtracting the wholly identifiable fixed costs from the total costs, not the Company.

Q. Did the Company state that costs other than the "wholly identifiable fixed costs" could "be avoided if BCC coal consumption was ramped down", as claimed by Mr. Burgess?

A. No.

[4] Sierra Club/100, Burgess/56.
[5] *Id.*
[6] Sierra Club/112, Confidential PacifiCorp Response to Sierra Club Data Request 2.5(c).

Q. Did the Company state that the list of "wholly identifiable fixed costs" was the entirety of the fixed costs to operate the BCC mines?

A. No. In fact, the Company's data response stated just the opposite. The data response stated, "Other fixed costs are embedded in labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs that are independent of coal production activities." Further, the Company stated, "the majority of labor costs would be considered fixed".[7]

Q. Did Mr. Burgess consider these other fixed costs identified by the Company when he calculated BCC's variable costs?

A. No.

Q. Is the testimony by Mr. Burgess that, "based on PacifiCorp's own accounting at least [redacted] of the BCC coal costs are variable and could therefore be avoided if BCC coal consumption was ramped down" accurate?

A. No. PacifiCorp actually stated that there were many other large cost categories that were included in fixed costs, especially for a one-year test period.

Q. Why aren't all costs at a mining operation variable costs that "could be avoided if BCC coal consumption was ramped down" as Mr. Burgess testified?

A. There are several reasons why costs do not vary directly with production levels. First, some cost categories are "wholly fixed" as the Company described them. These are cost categories that are incurred regardless of the level of operations, such as property taxes. Second, there are many activities that must be performed at the same level regardless of the level of operations, such as safety and environmental compliance.

[7] *Id.*

The cost categories to perform these activities include labor and supplies, which may appear to be variable cost categories, but the activity level is fixed. Third, the mining is most efficient, and costs are lowest, when the equipment is being operated at design capacity. Reducing production below this level will not reduce costs proportionately as the operation is less efficient at lower output.

Q. What is the proper methodology to estimate the fixed and variable costs for a mining operation?

A. The proper approach is to prepare complete mine plans and budgets for different levels of operations. The incremental costs to reduce production below design capacity divided by the incremental tons not produced would be the variable cost savings from reducing production. This variable cost is the cost that should be used for the "Dispatch Tier" in the GRID model.

Q. Is that the methodology followed by the Company to estimate the variable costs for BCC and to determine the Dispatch Tier price?

A. Yes, that is my understanding.

Q. Why do you state that the budget should start with the costs to operate at design capacity?

A. The design capacity of the BCC mines must be the level necessary to support the maximum coal consumption at the Jim Bridger power plant (less outside coal purchases). The Jim Bridger plant has four units with total capacity of 2,120 MW (66.7 percent owned by PacifiCorp). This is the largest coal plant in the Western grid and the largest power plant on PacifiCorp's system. Prior to 2016, the plant burned an average of [redacted] tons per year but has burned [redacted] tons per year over the last five years. Outside coal supplies are currently limited to the nearby Black Butte mine that produces [redacted] tons per year (to increase outside coal supply, the Company would need to make a major investment in coal unloading and handling capability). Historically, the BCC mines are designed and equipped to produce [redacted] tons per year, split roughly equally between the surface mine and the underground mine. For 2022, with the closure of the underground mine, the surface mining operation has a capacity between [redacted] tons per year. The BCC mine operations must be capable of producing at this level to support the output of the Jim Bridger power plant.

Q. Why can't BCC reduce production significantly or idle operations when demand for power from Jim Bridger is low?

A. BCC needs to maintain a workforce of qualified and experienced coal miners in order to operate the mine at design levels. While the coal miners may appear to be a variable cost to Mr. Burgess, the miners' living costs are largely fixed to them. If BCC were to reduce its workforce significantly, the miners would leave to find steady employment elsewhere. Then, when BCC wanted to resume or increase operations, it would not have a workforce to operate the mines. As a result, BCC needs to maintain reasonable steady operations to maintain a workforce and use the coal inventory fluctuations to support the variability in coal burn.

VI. PRUDENCE OF THE HUNTINGTON COAL CONTRACT

Q. Staff witness Rose Anderson recommends a disallowance to the 2022 TAM because of the minimum take provision in the Huntington coal contract. What is the basis of this recommended reduction?

A. The Huntington CSA was signed as part of a major transaction to close the Deer Creek coal mine, to sell other mining assets to Bowie Resources and enter a long-term CSA with Bowie Resources to replace the coal supply to the Huntington power plant. These transactions were linked together and were all presented to the Commission for approval in docket UM 1712 in 2015. Ms. Anderson's testifies that, while the Commission approved the closure of the Deer Creek mine (and the sale of assets), the Commission did not take any action regarding the reasonableness of the Huntington CSA. She opines that the minimum take provisions of the Huntington CSA is currently harming ratepayers and she recommends a disallowance because the Company has not demonstrated that the provisions of the Huntington CSA were prudent at the time they were agreed in 2014.

Q. Did you file testimony in docket UM 1712 in 2015?

A. Yes. I filed testimony supporting the Company's decision to close the Deer Creek mine, sell the mining assets, and replace the coal supply with the Huntington CSA.

Q. Did other parties, including Staff and Sierra Club, file testimony regarding the prudence of the transaction, including the Huntington CSA?

A. Yes. Testimony from other parties agreed that the closure of the Deer Creek mine and replacement with other Utah coal purchases would save money for the ratepayers.

Q. Did other parties question the need for the Huntington CSA, including the minimum take coal purchase requirement?

A. Yes. Staff and Sierra Club both questioned the need for a long-term replacement coal contract, especially concerns that the Company would not be able to close the Huntington plant if it faced new environmental compliance requirements and the risk that the Company may have to pay damages under the minimum take provisions in the CSA.

Q. Did the Company provide testimony and supporting analyses justifying the need for the Huntington CSA in docket UM 1712 in 2015?

A. Yes. The Company filed extensive testimony in support of the transactions and the Huntington CSA in that docket. The need for the CSA was fully debated by the Company and intervenors in that docket.

Q. Can you summarize the justification presented by the Company for the Huntington CSA in 2015?

A. The Company supported the need for the Huntington CSA based on the following factors:

- The Huntington CSA was an integral part of the package agreement with Bowie Resources. The coal supplier would not agree to purchase the mining assets without a long-term commitment to purchase coal by the Company.
- Supply of coal in the Utah market was extremely limited and would become much smaller when the Company closed the Deer Creek mine; thus entering the long-term CSA as part of the transaction would protect the Company from the increased market risk after the mine closed.

- The initial price of coal was below the market price at the time and the escalation rate in the CSA would keep the contract price below the future market prices expected at the time.
- The range of volumes in the Huntington CSA was large and favorable to the Company, with the minimum volume commitment of [redacted] tons per year well below the historical coal burn and the maximum amount capable of supplying the full plant requirements in periods of high burn.
- The Huntington CSA contained a clause allowing the Company to terminate the contract in the event that new environmental rules made the plant uneconomic, protecting the Company and ratepayers from this risk.

Q. Do you believe that the Company adequately demonstrated the prudence of the Huntington CSA based on what it knew or should have known at the time the contract was executed?

A. Yes, this issue was supported at the time with ample testimony and analysis.

Q. Have energy markets changed since the Huntington CSA was negotiated in 2014?

A. Of course. One of the biggest changes is that natural gas prices are much lower than industry participants expected in 2014. That change is the primary factor that led to reduced dispatch of the Huntington power plant.

Q. Has coal burn at Huntington fallen below the minimum take levels in the CSA?

A. No. Coal burn continues to exceed the minimum take levels under the CSA, even during the very low demand levels caused by the pandemic in 2020.

Q. In your opinion, was the Huntington CSA prudently entered into in 2014?

A. Yes. It was prudent at the time. The entire Deer Creek and Huntington transactions were a great benefit to the Company and its ratepayers at the time and have remained so during the last six years.

VII. COAL SUPPLY OPTIONS FOR THE HUNTER POWER PLANT

Q. What are the coal supply options for the Hunter power plant?

A. The Hunter plant is located near Castle Dale, Utah near the heart of the Utah coal fields. The plant can only take delivery by truck and is located about 32 miles from the nearest railroad. The plant was designed for the bituminous coal quality produced from the nearby mines (high heat and low sulfur content). The cost of transportation to bring in large quantities of coal from outside the state by rail and then trucked to the plant would be high and would only be practical if local Utah coal were unavailable.

Q. How does that affect the coal supply strategy for the Hunter plant?

A. PacifiCorp's coal supply strategy must focus on ensuring adequate supply from the local Utah mines. Because the coal supply options from the Utah mines are limited, PacifiCorp utilizes coal supply contracts with multiple producers to ensure that enough mines maintain operation to supply PacifiCorp's local needs at the Hunter plant and the Huntington plant, which is also located in Utah.

Q. What are the sources of coal production in Utah?

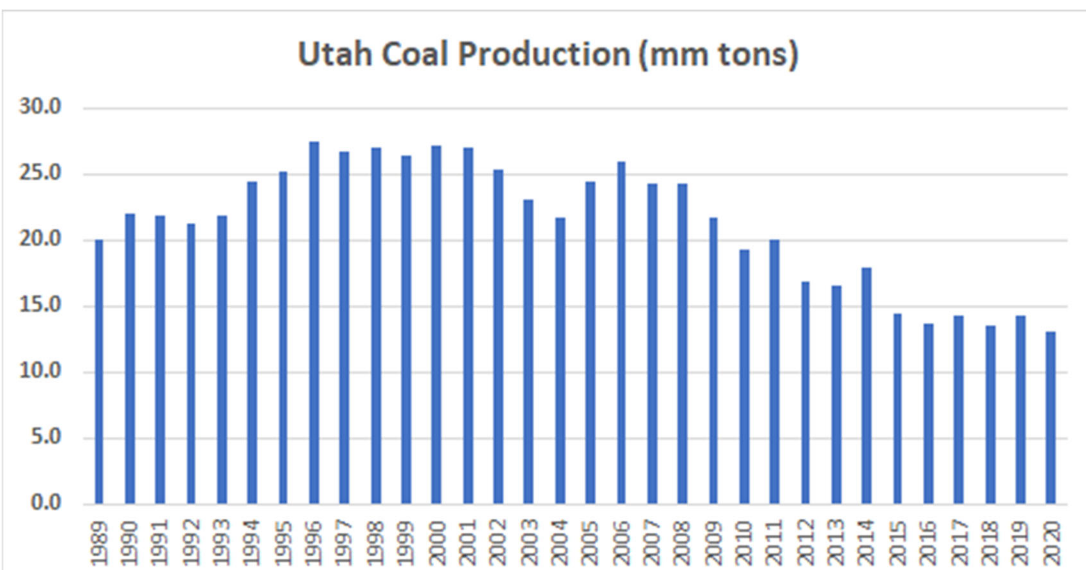
A. Utah coal is produced in four separate coal fields.[8] The Wasatch Plateau is the largest source of coal and is located just west of the Hunter power plant. This is the

[8] Utah Geological Survey, "Utah Mining 2019" at 26. https://ugspub.nr.utah.gov/publications/circular/c-130.pdf.

traditional source of coal for the Hunter plant, including from mines formerly owned and operated by PacifiCorp and its predecessor, Utah Power and Light. The Emery coal field is located south of the Hunter plant and Hunter is the closest market for coal produced from this coal field. The Book Cliffs coal field is located north of the Union Pacific railroad and is a longer truck haul to bring this coal south to the Hunter plant. Finally, the Alton coal field is located in southern Utah near the Kaiparowits Plateau. This coal is a long truck haul to Hunter and is a subbituminous coal quality, not typical of the coal used at the Hunter plant.

Q. How has coal production in Utah changed over time?

A. Utah coal production reached its peak in 1996 at 27.5 million tons. Output was fairly stable for the entire period from 1994 through 2008 at over 24 million tons per year in most years. Since 2008, Utah coal production declined steadily to under 15 million tons by 2015 and has been in the range of 13.0 – 14.5 million tons per year since then.[9]



[9] Mine Safety and Health Administration data. https://www.msha.gov/mine-data-retrieval-system.

Q. What is the demand for Utah coal?

A. Utah coal markets are very limited. The largest demand is at domestic power plants, typically close to 10 million tons per year. PacifiCorp is the largest customer at about 6 to7 million tons per year. The only other power plants that purchase Utah coal are the large Intermountain plant in Utah (owned primarily by California municipal utilities) and the small North Valmy plant in Nevada. A variety of small industrial customers use 1.5 – 2.0 million tons per year, primarily at cement and lime kilns. The export market accounts for the remaining demand which can be up to 2.5 million metric tons depending on world coal markets. Utah coal is exported to Asian customers through ports in California.[10]

Utah Coal Demand 2020

Sector	Company	Plant	State	1000 tons
Power				**10,076**
	PacifiCorp	Hunter	UT	4,918
		Huntington	UT	2,039
	LADWP	Intermountain	UT	2,842
	NV Energy	North Valmy	NV	277
Industrial				**1,545**
Export (est.)				**1,542**
Total Production				**13,163**

Q. What are the active coal mines in Utah?

A. There are six active coal mines in Utah owned by five separate companies. The majority of Utah coal is produced by Wolverine Fuels (formerly Bowie Resources and Canyon Fuels). Wolverine produces 8-10 million tons per year from two large longwall mines, both in the Wasatch coal field. These mines are the lowest-cost operations in Utah and the primary supply to PacifiCorp's Hunter and Huntington

[10] Energy Information Administration, coal distribution data. https://www.eia.gov/coal/distribution/quarterly/

power plants. Wolverine idled the Dugout Canyon mine in 2019. The other nearby mines are the Emery mine (in the Emery coal field) and the Castle Valley mine in the Wasatch field. The Emery mine was redeveloped by Bronco Energy in 2017 and its output is growing to over 1.5 million tons per year. The Castle Valley mine was operated by Rhino Energy until late 2020 when it was sold out of bankruptcy to Gentry Mountain Resources. Castle Valley has produced close to 1.0 million tons per year. The Lila Canyon mine is a large longwall mine in the Book Cliffs coal field that primarily sells in the rail markets (including export and industrial) but is also a source of coal for the Hunter and Huntington plants. The last mine is the Coal Hollow mine of Alton Coal, producing about 0.5 million tons per year. Virtually all this coal is trucked to the Intermountain power plant.

Utah Coal Production (1000 tons)

Coal Field	Company	Mine Complex	Mine	Type	2016	2017	2018	2019	2020
Book Cliffs	ACNR	Lila Canyon	Lila Canyon	U	1,587	1,629	2,631	3,714	3,302
Alton	Alton Coal	Coal Hollow	Burton #1	U	34	-	-	-	-
Alton	Alton Coal	Coal Hollow	Coal Hollow	S	669	724	488	240	569
Emery	Bronco Coal	Emery	Emery Mine	U	-	129	442	693	474
Wasatch	Rhino Energy	Castle Valley	Castle Valley #4	U	724	783	871	417	11
Wasatch	Rhino Energy	Castle Valley	Gentry	U	170	175	103	563	660
Book Cliffs	Wolverine Fuels	Dugout Canyon	Dugout Canyon	U	650	626	550	416	-
Wasatch	Wolverine Fuels	Skyline	Skyline	U	4,538	4,375	3,603	3,916	3,688
Wasatch	Wolverine Fuels	Sufco	Sufco	U	5,375	5,884	4,904	4,374	4,459
					13,747	**14,326**	**13,591**	**14,334**	**13,163**

Q. How does the nature of Utah coal supply and demand affect the coal procurement plans for the Hunter power plant?

A. Because of the small number of Utah coal suppliers and customers, there is little Utah coal sold on the "spot" market (sales contracts under one year in length). PacifiCorp cannot expect to be able to purchase significant amounts of additional coal to meet burn under spot contracts on short notice. As a result, PacifiCorp must design a procurement strategy to have the ability to supply the range of its expected burn under longer-term contracts.

Q. How does the Company accomplish that objective?

A. PacifiCorp enters contracts with multiple Utah coal producers that provide some degree of volume swing at the option of PacifiCorp to meet its burn requirements. In return for minimum volume commitments, PacifiCorp can obtain enough volume swing capability to meet the range of its expected burn.

VIII. PRUDENCE OF NEW HUNTER CSAs

Q. Mr. Burgess recommended that "the Commission should deem the new Hunter CSA minimum take quantities to be imprudent."[11] Do you agree?

A. No. In my opinion, the new CSAs for the Hunter plant were prudently entered into by the Company, including the sources, term, pricing, and quantities.

Q. What are the reasons provided by Mr. Burgess in support of his opinion that the Commission should find that the new Hunter CSAs are imprudent?

A. Mr. Burgess stated that "PacifiCorp has not done enough to demonstrate that the coal supply agreements at Hunter are prudent."[12] His reasons are "the agreements include very high minimum take provisions," "Hunter's forecasted generation levels are extremely close to the minimum take quantity," "the new contracts [redacted]" and "it would be appropriate for PacifiCorp to complete an analysis of potential alternatives."[13]

[11] Sierra Club/100, Burgess/74.
[12] Sierra Club/100, Burgess/49.
[13] Sierra Club/100, Burgess/50.

Q. Do you agree that "PacifiCorp has not done enough to demonstrate that the coal supply agreements at Hunter are prudent"?

A. No. The Company has provided extensive supporting testimony and documents to show the process that it went through to enter these new CSAs, including the analysis of projected burn, the solicitation of new coal supplies, the evaluation of coal supply alternatives, and the negotiation of the contracts along with their terms and conditions.

Q. Do you agree that the new CSAs have very high minimum take provisions?

A. No. Mr. Burgess has correctly calculated that the minimum take obligations under the new Hunter CSAs are equal to [redacted] of the [redacted] burn under the "high" burn forecast and [redacted] of the [redacted] average burn under the "low" burn forecast. Compared to the "expected" burn forecast, the minimum take requirements are [redacted] of the [redacted] projected "average" quantity needs (the expected burn was not mentioned by Mr. Burgess). For the Company to be over-contracted for coal, the coal burn at Hunter would have to be at least [redacted] below the "low" burn forecast and [redacted] below the "expected" burn forecast, not just for one year – for all [redacted]. Thus, it is extremely unlikely that the Company has entered minimum take obligations that will be below the burn requirements at the Hunter plant.

Q. What is the basis for Mr. Burgess' opinion that these minimum take obligations are too high?

A. Mr. Burgess opined that minimum take provisions should be set at no more than 50 percent of projected consumption. In his testimony Mr. Burgess provided no basis for his selection of the 50 percent figure. In responses to data requests from PacifiCorp, Mr. Burgess simply repeated that "Mr. Burgess's recommendation is based on his expert opinion and professional judgment that minimum take requirements exceeding a certain percentage of projected coal fuel burn are imprudent."[14] He provided no other source, analysis or basis for the selection of 50 percent as a threshold for determination of imprudence in coal contract commitments.

Q. Did Mr. Burgess assert that it was the practice of other utilities to restrict contracting to no more than 50 percent of anticipated coal burn for the upcoming year?

A. No.

Q. In your experience, what is the practice of other utilities regarding the contracting for coal compared to the anticipated coal burn for the upcoming year?

A. I have had 40 years' experience consulting for utilities, merchant power generators, and industrial consumers in support of their fuel procurement practices. I have drafted coal procurement plans and have audited coal procurement plans on behalf of utility commissions and intervenors. In all my experience, I have never encountered a coal buyer willing to have as little as 50 percent of its projected burn under contract for the upcoming year. In my experience, it would be highly risky for a utility to have so little coal purchased under contract for the upcoming year.

[14] PacifiCorp Data Request 1.7, attached as Exh. PAC/502.

Q. Why is it standard utility practice to have greater than 50 percent of expected coal burn under contract for the upcoming year?

A. Because the utility would be assuming significant risk that it would not be able to purchase enough coal to support its generation, as it would have to purchase 50 percent of its expected coal supply on the spot market.

Q. Did Mr. Burgess consider the risk of PacifiCorp not having enough coal to support its generation needs?

A. Mr. Burgess dismissed the risk of the Company not having enough fuel at the Hunter plant because it had high coal inventories. However, his recommendation that contract commitments over 50 percent applies not just to Hunter in 2021, when it happens to have high inventories; he wants the Commission to establish a threshold for scrutiny of contract commitments above 50 percent of expected burn at all plants in all years, regardless of inventory levels.

Q. What would be the potential consequences of PacifiCorp not having enough coal to support its generation needs?

A. The risk of running short of coal is that PacifiCorp would have insufficient power generation to meet customer needs, resulting in customer power supply interruptions or significant price volatility. The cost to customers of such an event is far more than can be quantified in monetary terms. The recent power shortages in Texas were caused in part by lack of fuel deliverability during a period of high customer demand. When there is an event of high customer demand, it tends to be correlated with an inability to purchase additional fuel for generation—because demand is high for all the power generators at the same time. It is incumbent upon a load-serving utility to protect against the potential to be short of fuel supply—not just to protect against having too much under contract.

Q. Does the structure of the coal market in which the utility operates affect the amount of coal that is prudent to have under contract for the upcoming year?

A. Yes. As explained above, coal markets vary as to their degree of "liquidity"—the availability of coal that can be purchased with little advance notice without significantly affecting the market price. In highly liquid markets, a utility can rely upon shorter-term ("spot") purchases to supply much of its needs. Coal markets are much less liquid than markets for natural gas or electric power because coal must be delivered in discrete shipments (not continuously like pipelines or transmission lines) and coal quality varies by coal basin and mine (power plants are only able to burn specific coals; coal supplies are not commingled like natural gas or power). Liquidity varies among coal markets. The international market tends to be more liquid because there are a wide range of potential suppliers and transportation options. In the domestic U.S. coal markets, the Powder River Basin is a more liquid market with multiple suppliers of coal with very similar quality and transportation. However, the Utah coal market is relatively illiquid, with just a few mines with limited capacity. The amount of expected burn needed to be under contract in the Utah coal market is higher than average for U.S. utilities.

Q. Did Mr. Burgess provide or reference any studies to support his opinion that contracting for more than 50 percent of anticipated coal burn for the upcoming year is imprudent?

A. Mr. Burgess did not provide any studies or data to support his opinion that a utility should not contract for greater than 50 percent of expected burn for the upcoming year.

Q. Have you analyzed the fuel purchase data reported to the federal government to determine what share of coal purchases are made under contract compared to spot market purchases?

A. Yes. All power generators report their fuel purchases to the Energy Information Administration (EIA) on Form 923. I regularly work with the EIA Form 923 data in my normal course of business. One of the parameters reported to EIA is whether coal was purchased under contract or on the spot market. I have analyzed the data reported for calendar year 2020 to EIA to determine the percentage of coal that was spot market purchases.[15] There were 431.2 million tons of coal purchases in calendar year 2020 by power generators. Only 9.6 percent (41.5 million tons) were reported to be spot market purchases—not 50 percent or anywhere close to that number.

Q. Was there a higher percentage of Utah coal purchased on the spot market?

A. No. The percentage of Utah coal purchased on the spot market in 2020 was only 2.6 percent.

[15] Energy Information Administration, Form 923. https://www.eia.gov/electricity/data/eia923/.

Q. Have you evaluated the normal industry practice for percentage of coal contracted for the upcoming year?

A. Yes. The publicly traded U.S. coal companies typically disclose the amount of coal that they have under contract for the upcoming year. These companies inform investors in filings with the Securities and Exchange Commission their earnings guidance for the upcoming year, including projected coal sales and the amount of coal sales already committed under contract. Many of the largest U.S. producers of thermal coal (coal burned in power plants) are public companies and I have analyzed their public disclosures to determine the amount of coal they have committed under contract for the year 2021. All six of these large public companies had at least 79 percent of their projected 2021 coal sales committed under contract by early 2021.[16][17][18][19][20][21]

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[16] Peabody Energy, 2020 Q4 earnings release, February 4, 2021, https://www.peabodyenergy.com/Media-Center/Newsroom.

[17] Arch Resources, 2020 Q4 earnings release, February 9, 2021, https://investor.archrsc.com/news-releases/news-release-details/arch-resources-reports-fourth-quarter-2020-results.

[18] Alliance Resource Partners, 2020 Q4 earnings release, February 1, 2021, https://www.arlp.com/investor-relations/press-releases/press-release/2021/Q4-2020-Earnings-Release/default.aspx.

[19] Consol Energy, 2020 Q4 earnings release, February 9, 2021, http://investors.consolenergy.com/2021-02-09-CONSOL-Energy-Announces-Results-for-the-Fourth-Quarter-and-Full-Year-2020.

[20] Alpha Metallurgical Resources, 2020 Q3 earnings release, November 9, 2020, https://alphametresources.com/news/contura-announces-third-quarter-2020-results/.

[21] Hallador Energy, 2020 Q3 earnings release, November 2, 2020, https://www.halladorenergy.com/news-events/news-releases/news-details/2020/Hallador-Energy-Company-Reports-Third-Quarter-2020-Financial-and-Operating-Results/default.aspx.

	2021 Thermal Coal Sales (mm tons)		
Company	**Projected**	**Committed**	**% Contract**
Peabody Energy	103.0	85.6	83%
Arch Resources	52.0	49.8	96%
Alliance Resource Partners	30.7	24.1	79%
Consol Energy	23.0	18.2	79%
Alpha Met Resources	7.3	7.3	100%
Hallador Energy	6.0	5.4	79%

Q. Does this analysis provide a reliable measure of the amount of coal that utilities had under contract entering the year 2021?

A. Yes. If all the major U.S. thermal coal producers had at least 79 percent of their projected thermal coal sales for 2021 committed under contract, it is reasonable to conclude that most utility customers had at least 79 percent of expected coal purchases for 2021 under contract commitments.

Q. If the burn at Hunter turns out to be below the Company's forecast of expected burn, will the Company have committed to too much coal under the minimum take provisions in its new CSAs?

A. No. The minimum take provisions under the Hunter CSAs are only equal to [redacted] of the expected three-year average burn at Hunter. Even if the burn at Hunter turns out to be [redacted] below the expected burn, the Company will not have a problem meeting its minimum take obligations under the new CSAs.

Q. Have you considered the historical coal burn at the Hunter plant?

A. Yes. The variability of the historical coal burn is a good measure of the risk of the burn being below the forecast. Over the last 23 years from 1998 through 2020, the average coal burn at the Hunter plant was [redacted] tons per year. The burn in the lowest year on record was [redacted] tons. The Company's forecast of coal burn for the next three years is an average of [redacted] tons. The Company's model forecasted coal burn to range from a low of [redacted] tons per year to a high of [redacted] tons per year. The cumulative minimum take requirements in the new CSAs is only [redacted] tons per year, [redacted] below the low burn forecast and [redacted] below the expected coal burn. There is little risk that the minimum take provisions will exceed the coal burn over the next three years and the commitment is certainly not imprudent.

Q. Does Mr. Burgess criticize the "inflexibility" of the Hunter CSA minimum purchase requirements?

A. Yes. Mr. Burgess testified "As discussed throughout my testimony, multi-year coal supply agreements with inflexible minimum purchase requirements leave the Company with no flexibility to adjust to evolving market conditions."[22]

Q. Do you agree that the Company has entered "inflexible" new CSAs for the Hunter plant?

A. No. Actually, the new Hunter CSAs have a large degree of volume flexibility, allowing the Company under one contract to nominate [redacted] more than the minimum take for any contract year and under the second contract up to [redacted] more than the minimum take (based on plant requirements). In my experience, this is a remarkably high degree of flexibility "to adjust to evolving market conditions." I would have expected Mr. Burgess to praise the Company for its flexible coal purchase agreements, not ask the Commission to deem them to be imprudent.

Q. Does this conclude your reply testimony?

A. Yes.

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[22] Sierra Club/100, Burgess/35.

Docket No. UE 390
Exhibit PAC/501
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Seth Schwartz

Seth Schwartz' Resume

July 2021

RESUME OF
SETH SCHWARTZ

EDUCATIONAL BACKGROUND

B.S.E. Geological Engineering, Princeton University, 1977

PROFESSIONAL EXPERIENCE

Current Position

Seth Schwartz is the President and co-founder of Energy Ventures Analysis. Mr. Schwartz directs EVA's coal and power practice and manages the COALCAST Report Service. The types of projects in which he is involved are described below:

Fuel Procurement
Assists utilities, industries and independent power producers in developing fuel procurement strategies, analyzing coal and gas markets, and in negotiating long-term fuel contracts.

Fuel Procurement Audits
Audits utility fuel procurement practices, system dispatch, and off-system sales on behalf of all three sides of the regulatory triangle, i.e., public utility commissions, rate case intervenors, and utility management.

Coal Analyses
Directs EVA analyses of coal supply and demand, including studies of utility, industrial, export, and metallurgical markets and evaluations of coal production, productivity and mining costs.

Natural Gas Analyses
Evaluates natural gas markets, especially in the utility and industrial sectors, and analyzes gas supply and transportation by pipeline companies.

Expert Testimony
Testifies in fuel contract disputes and rate cases, including arbitration, litigation and regulatory proceedings, regarding prevailing market prices, industry practice in the use of contract terms and conditions, market conditions surrounding the initial contracts, and damages resulting from contract breach.

Acquisitions and Divestitures
Assists companies in acquisitions and sales of reserves and producing properties, both in consulting and brokering activities. Prepares independent assessments of property values for financing institutions.

Prior Experience

Before founding Energy Ventures Analysis, Mr. Schwartz was a Project Manager at Energy and Environmental Analysis, Inc. Mr. Schwartz directed several sizable quick-response support contracts for the Department of Energy and the Environmental Protection Agency. These included environmental and financial analyses for DOE's Coal Loan Guarantee Program, analyses of air pollution control costs for electric utilities for EPA's Office of Environmental Engineering and Technology, Energy Processes Division, and technical and economic analysis of coal production and consumptions for DOE's Advanced Environmental Control Technology Program.

Publications

Crerar, D.A., Susak, N.J., Borcsik, M., and Schwartz, S., "Solubility of the Buffer Assemblage Pyrite + Pyrrhotite + Magnetite in NaCl Solutions from 200^{o} to 350^{o}", Geochimica et Cosmochimica Acta (42)1427-1437, 1978.

Docket No. UE 390
Exhibit PAC/502
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Seth Schwartz

PacifiCorp Data Request 1.7

July 2021

Docket No. UE 390
Sierra Club
June 29, 2021
PacifiCorp Data Request 1.7

PacifiCorp Data Request 1.7

Please refer to SC/100, Burgess/35, lines 13-15 where Mr. Burgess states that "the Commission should conduct additional scrutiny for any coal supply agreements that include a minimum take quantity that is over 50 percent of the forecasted need." Please provide the basis for Mr. Burgess's choice of a 50 percent threshold for a minimum take quantity. Please include any workpapers, studies, articles to support this number.

Response to PacifiCorp Data Request 1.7

Mr. Burgess's recommendation is based on his expert opinion and professional judgment that minimum take requirements exceeding a certain percentage of projected coal fuel burn are imprudent. When evaluating new CSAs, a higher percentage of minimum take (relative to projected burn) corresponds to a higher level of risk to ratepayers that the minimum will not be met unless the coal plant is dispatched uneconomically. There are a variety of external factors outside of PacifiCorp's control that could cause the economic amount of coal burn to be lower than projected. Additionally, the economics of coal fuel faces greater uncertainty now than in the past due to rapidly evolving federal and state policies. Thus, it may be appropriate for the Commission to analyze whether these risk factors outweigh the benefits of any level of minimum take. However, in Mr. Burgess' professional judgement, it is especially appropriate for the Commission to conduct this analysis for CSAs above the 50 percent threshold due to the higher level of risk involved.

Mr. Burgess's analysis, contained in his opening testimony, demonstrates that PacifiCorp's minimum-take obligations have locked ratepayers into paying for the operation of PacifiCorp's coal fleet, even when it is not economic to do so. Additional scrutiny for minimum take requirements that exceed 50 percent of anticipated coal burn is needed as the Company has often failed to sufficiently model anticipated coal needs for its plants, as outlined in OPUC Staff's Opening Testimony. Even when the Company has evaluated anticipated coal needs and claimed to have contracted for minimum take provisions far below anticipated burn, the minimum take provisions have nevertheless translated into nearly 100 percent of forecasted fuel burn in the Company's GRID modeling used for NPC forecasts.

REDACTED
Docket No. UE 390
Exhibit PAC/600
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Dana M. Ralston

July 2021

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Confidential Exhibit PAC/602—1st Supplemental Response to OPUC Data Request 154

Q. Are you the same Dana Ralston who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the opening testimony of Mr. John Fox and Ms. Rose Anderson, filed on behalf of Staff, Mr. Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB), and Mr. Ed Burgess, filed on behalf of the Sierra Club.

Q. Please summarize your testimony.

A. My testimony first provides an update to the coal costs that have been included in the 2022 Transition Adjustment Mechanism (TAM) Reply forecast. My testimony additionally explains the prudence of the new Coal Supply Agreements (CSAs) at the Dave Johnston, Craig and Hunter Facilities, including the appropriateness of the minimum take provisions in those CSAs. Additionally, I discuss the prudence of PacifiCorp's decision to enter into the Huntington CSA. Also, I respond to certain specific concerns from Staff and AWEC regarding Jim Bridger and Bridger Coal Company (BCC).

II. TAM REPLY UPDATE TO COAL COSTS

Q. Has total coal-fuel expense in the 2022 TAM update increased from the level reflected in PacifiCorp's 2022 TAM initial filing?

A. Yes. As stated in the testimony of Mr. Douglas R. Staples, total coal-fuel expense has increased by $8.9 million—from $543.4 million in this initial filing in the 2022

TAM to $552.3 million in this update filing in the 2022 TAM. This increase is a result of higher coal prices by approximately $7.2 million and increased coal-fired generation volume of $1.7 million.

Q. Please identify the primary drivers of the $7.2 million fuel expense increase due to higher coal prices in the reply update compared to the initial filing.

A. Affiliated captive mine unit cost increases result in a [redacted] fuel expense increase, related to reduced supplemental coal delivered by BCC to Jim Bridger plant as shown in Confidential Table 1 below. Supplemental coal deliveries from BCC above the base mine plan decreased by [redacted] tons. Because the incremental BCC coal is produced at a lower unit cost than the base mine plan coal, the total weighted-average unit cost is increased by reduced deliveries of supplemental coal resulting in an increase to fuel expense.

Confidential Table 1: Coal and Transportation Contract Price Variance

Plant	Contract	Millions ($)
Naughton	Kemmerer Coal	[redacted]
Wyodak	Wyodak Coal	
Dave Johnston	Powder River Basin Coal	
Dave Johnston	BNSF Rail	
Jim Bridger	Bridger Coal	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR Rail	
Hunter	Wolverine Coal	
Huntington	Wolverine and Castle Valley Coal	
Colstrip	Rosebud Coal	
Craig	Trapper	
Hayden	Twentymile Coal and UPRR Rail	
Total Coal Price Increase/(Decrease)		

Third-party coal purchases and transportation unit cost increases result in a [redacted] fuel expense increase. The primary drivers for the increase in fuel cost is due to higher contract indices and diesel fuel costs at the Wyodak, and Colstrip plants. There are also increases for Dave Johnston and Jim Bridger rail costs for higher diesel fuel costs. The increase at Hunter is primarily due to an excise tax pass through from the suppliers partially offset by an increase of tier 2 coal purchases. The increase at the Dave Johnston plant is due to an excise tax pass through from the suppliers and a small increase to the market price for the spot coal.

III. RESPONSE TO STAFF

New Coal Supply Agreements

Dave Johnston

Q. Staff questions the Company's decision to rely on CSAs to fuel the majority of the coal burned at the Dave Johnston plant.[1] What is the basis of Staff's concern?

A. Staff testifies that the pricing in the new CSAs for the plant are higher than the current spot market prices and based on that comparison concludes that "increasing the amount of contracted supply while losing the advantage of below market pricing doesn't seem to make financial sense."[2]

Q. Did Staff propose an adjustment?

A. No. But Staff asked the "Company to provide additional evidence that entering into a contract above the spot price is reasonable over the contract term."[3]

[1] Staff/600, Fox/5.
[2] Staff/600, Fox/27.
[3] Staff/600, Fox/27.

Q. How do you respond to Staff's concern?

A. As an initial matter, there is no differentiation between what Staff describes as "contracting" and "purchasing on the open market."[4] The differentiation made in Staff's testimony is better explained as the difference between future purchases currently under contract and those yet to be contracted. Staff testifies that the 2022 average price for all coal currently contracted, which includes the two CSAs signed in 2020, ([redacted] per ton) is higher than current spot market pricing ([redacted] per ton) and based on that comparison concludes that it does not make financial sense to enter into new CSAs for the open position at Dave Johnston. However, Staff's comparison of current spot market prices to the pricing included in multi-year contracts is incorrect and does not demonstrate that the pricing in the CSAs is unreasonable.

First, Staff is averaging market pricing for 2022 that was available in the third quarter of 2019 (when the Coal Creek and first Caballo contract were signed) and market pricing for 2022 available in the fourth quarter of 2020 (when the North Antelope Rochelle Mine (NARM) and second Caballo contracts were signed). Staff then took that average price ([redacted] per ton) and compared it to the estimated spot market price for 2022 coal as published in the first quarter of 2021 ([redacted] per ton). Based on this comparison, Staff concludes that the Company is overpaying [redacted] per ton on all the coal currently under contract. Because the Powder River Basin (PRB) spot price index varies over time, however, Staff's comparison of pricing from different time periods is an apples-to-oranges comparison. For example, the

[4] Staff/600, Fox/27 (comparing the costs of "contracting rather than purchasing on the open market.").

Company negotiated the two most recent CSAs (the NARM and second Caballo contracts) in the third quarter of 2020, and the agreements were eventually signed in fourth quarter of 2020. The 2022 NARM CSA price is [redacted] per ton and the 2022 Caballo CSA price is [redacted] per ton. The relevant estimated spot prices for purposes of comparison were those prevailing when the contracts were negotiated. At that time, the spot market price for 2022 was [redacted] per ton, which is significantly higher than the CSA prices. Therefore, contrary to Staff's claims, the Company did not enter "into a contract above the spot price" in 2020.

Second, the Company purchases all the Dave Johnston plant's coal requirement pursuant to Requests for Proposals from coal mines in the PRB. As necessary, the Company solicits coal proposals from all Wyoming coal mines located in the PRB. The least-cost, least-risk coal proposal is then selected from the responses received and a contract is executed for the purchase. This process assures customers that the coal consumed at Dave Johnston is purchased at the prevailing market price, as the Company canvasses the entire market.

Q. Is Staff's analysis missing important elements that must also be considered when evaluating the prudence of a CSA?

A. Yes. Staff's analysis simply considers the cost of coal on an FOB mine basis. The Company is required to analyze coal purchases on a delivered cost basis (FOB plant). In addition, the PRB spot market index used by the Company to estimate current spot market pricing is standardized on an 8,400 British thermal unit per pound (Btu/lb.) basis. The heat content of coal purchased for Dave Johnston ranges from 8,000 Btu/lb. from 8,900 Btu/lb. Staff's analysis did not consider the impact of transportation and heat content differences and therefore does not indicate that the new CSAs are imprudent or that the Company should not contract for additional supplies to fill the open position at Dave Johnston.

Q. Please explain why the Company does not purchase all of Dave Johnston's coal on a just-in-time spot basis.

A. While obtaining favorable pricing is important in a CSA, a contract also provides fuel security, as described in more detail by Mr. Seth Schwartz. Even for a plant like Dave Johnston that has access to a relatively liquid coal market, security of supply provides value that must be considered when evaluating the prudence of a multi-year CSA. As demonstrated above, the Company's long-followed procurement process for purchasing PRB coal for the Dave Johnston plant allows the Company to both obtain favorable market pricing and maintain security of supply for the plant.

Jim Bridger

Q. Please describe Staff's concern regarding the third-party CSA for the Jim Bridger plant.

A. Staff testifies that Jim Bridger is one of the Company's highest cost resources at [redacted] per megawatt-hour (MWh) compared with the average of [redacted] per MWh and therefore the Company needs to provide additional evidence that it is prudent to renew the third-party CSA with the Black Butte mine.[5]

Q. Did Staff proposed an adjustment related to the Black Butte contract?

A. No.

[5] Staff/600, Fox/19.

Q. How do you respond to Staff's concern over the prudence of the renewal of the Black Butte contract?

A. Staff recognizes that the Company expects to renew the Black Butte contract at a price that is [redacted] less than the price of coal supplied by BCC.[6] Without that contract, BCC could not deliver the Jim Bridger plant's required coal by itself. Given that there is no market alternative for Black Butte coal, it is unclear why Staff believes that it is imprudent to renew the Black Butte contract.

Q. Does coal supplied by the Black Butte mine remain a critical component of the Company's long-term fueling strategy for Jim Bridger?

A. Yes. PacifiCorp's Long-Term Fuel Supply Plan for the Jim Bridger Plant, which was filed as part of the 2019 TAM[7] and updated as part of the 2020 TAM,[8] demonstrated that long-term use of Black Butte coal remained critical to PacifiCorp's least-cost, least-risk fueling strategy for Jim Bridger. Together with the fact that Black Butte coal is the least cost alternative coal supply for Jim Bridger demonstrates the reasonableness of PacifiCorp's decision to renew the CSA. Mr. Schwartz additionally addresses how the capacity from BCC and the Black Butte contract work together to meet the fueling requirements for the Jim Bridger plant.

[6] Staff/600, Fox/18-19.
[7] Docket No. UE 339, PAC/204.
[8] Docket No. UE 356, Exhibit PAC/201.

Minimum Take Provisions

Q. Staff, along with Sierra Club and CUB, express concern over the continued inclusion of minimum take (or "take or pay") provisions in PacifiCorp's coal supply agreements.[9] Have similar concerns been raised in prior TAMs?

A. Yes. In the 2017 TAM, CUB challenged the prudence of minimum-take provisions in three of the Company's coal contracts: the Black Butte contract for Jim Bridger, and the Huntington and Dave Johnston coal contracts. The Commission rejected CUB's proposed disallowance, finding that minimum take provisions are standard in coal supply contracts and that the alternative would be for the Company to rely on the spot market for coal, which would create both supply and price risks. Additionally, the Commission observed that two of the three contracts challenged by CUB were short-term.[10]

Q. Did any other party raise issues with respect to minimum take provisions in the 2017 TAM?

A. Yes. Staff also challenged the manner in which the Company accounted for the effects of minimum take provisions in its Generation and Regulation Initiative Decision Tools (GRID) modeling. As discussed in more detail in Mr. Staples's testimony, the Commission also rejected this challenge, observing that the Company's practice of iteratively adjusting GRID to model minimum take provisions was consistent with PacifiCorp's practice in prior TAM proceedings.[11]

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[9] *See, e.g.,* Staff/700, Anderson/10.
[10] Order No. 16-482 at 9.
[11] *Id.* at 10-11.

Q. What are Staff's specific concerns regarding minimum take provisions in this case?

A. Staff notes that the minimum take provisions at Dave Johnston, Hunter, Craig, and Huntington remain intact regardless of whether the Company chooses to close the plant for economic reasons.[12] This is true, but as explained in Staff's testimony in this case, voluminous prior TAM testimony, and again in the testimony of Mr. Schwarz, minimum take provisions are critical for obtaining CSAs, even the short-term contracts PacifiCorp is currently executing. Additionally, as noted above, the Commission previously found that minimum take provisions are "typical in coal supply agreements and that, without entering into supply agreements with these types of provisions, it would have to rely on the spot market with the attendant supply and price risk."[13]

Q. Please describe PacifiCorp's overall fueling strategy for its coal plants.

A. PacifiCorp's goal in fuel supply planning is still to secure the least-cost, least-risk fuel supply for customers. The Company begins with an estimate of the annual and future generation forecast of the plants, developed by considering many factors including historical usage patterns, sales and load forecasts, market prices, changes in available generation, operating lives and reliability requirements. The Company then develops fuel volume, pricing and sourcing assumptions, transportation costs, and if necessary, operating and capital costs for the plant. Where a plant is supplied by a dedicated, jointly owned mine, PacifiCorp collaborates with other owners to develop a mine

[12] Staff/700, Anderson/10.
[13] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 9 (Dec. 20, 2016).

plan to support the long-term fueling forecast. The costs from all sources are combined and evaluated to create the least-cost, least-risk fueling plan.

Q. Please describe PacifiCorp's general approach to obtaining its CSAs.

A. Consistent with past practice, PacifiCorp continues to negotiate third-party fuel contracts to meet its generation forecasts in the least-cost, least-risk manner. The Company's process in developing and negotiating contracts considers and evaluates factors like term, price, volume, supplier credit worthiness, plant location/coal region, coal supply options, coal transportation options, and coal quality. To minimize risk and add flexibility to its system planning, the Company limits the term of its coal supply agreements as much as practicable.

Q. Please describe the challenges associated with negotiating CSAs.

A. As explained by PacifiCorp's expert witness Mr. Schwartz in his reply testimony, coal is unlike other commodities, as there is no central, liquid market for coal supply. Coal quality specifications vary by region, transportation costs are significant, and many coal plants are located in areas where supplies are limited. Therefore, the Company must consider term, price, volume, and coal quality when negotiating third-party coal supply agreements and seek to strike the optimum balance among these factors. Negotiations for bilateral coal supply agreements are specific to the individual plant, mine or mines that can serve the plant, transportation requirements and overall coal market.

Q. Do minimum take and liquidated damages provisions remain a standard aspect of coal supply contracts?

A. Yes. As Mr. Schwartz also testifies, minimum take and liquidated damages provisions are an essential component of virtually all coal supply agreements and constitute the consideration required to obtain favorable pricing and receive security of supply.

Q. Please explain why the Company executes coal supply contracts with minimum take or liquidated damages provisions.

A. Coal supply contracts, which necessarily include minimum take provisions, ensure that a reliable supply of coal will be available to fuel the Company's plants at known and predictable prices, terms, and conditions. Absent a CSA, the Company would be required to supply its plants exclusively with spot market purchases. Relying exclusively on the spot market is an extremely risky strategy that would expose customers to substantial and unreasonable price and supply risk, especially in the illiquid markets in which most of PacifiCorp's coal generation is located. In his testimony, Mr. Schwartz demonstrates that there is little or no coal available on the spot market to serve PacifiCorp's coal plants, with the exception of the Dave Johnston plant located near the PRB.

Q. Do minimum take provisions create limitations that harm customers?

A. No. In fact, the exact opposite is true. Minimum-take contracts significantly reduce the risk associated with coal supply availability. Multi-year contracts significantly reduce the risk to customers associated with market price volatility or fluctuations. It would be substantially higher risk if the Company did not have fuel for electricity generation during certain times of the year. These provisions are especially important for a majority of PacifiCorp's coal fleet because of the inability to receive significant quantities of coal from other sources.

Q. How does PacifiCorp seek to maintain flexibility even though its CSAs must include minimum take provisions?

A. As noted above, to minimize risk and add flexibility to its system planning, the Company's current strategy is to limit the term of its coal supply agreements as much as practicable. This strategy allows the Company to continually reassess its least-cost, least-risk resource portfolio in its integrated resource plan (IRP). The Company has used the long-term fuel plan for the Jim Bridger plant to analyze and support it's fueling strategy and to optimize BCC operations. PacifiCorp has also included environmental response or change of law provisions where possible in its contracts with longer terms.

Q. Please describe Staff's two concerns related to how the Company negotiates minimum take levels in its CSAs.[14]

A. First, Staff questions the Company's duration of the generation forecasts that the Company uses to support the negotiated minimum take levels. Second, Staff is concerned that the Company does not adequately consider economic cycling when forecasting generation for purposes of negotiating a minimum take provision. My testimony addresses Staff's first concern and addresses why economic cycling at Dave Johnston and Craig is not practical. Mr. Daniel J. MacNeil addresses the analysis that was conducted for the Hunter CSA. Mr. Staples's testimony addresses economic cycling generally.

[14] Staff/700, Anderson/11.

Q. How do you respond to Staff's first concern regarding the duration of generation forecasts used to determine reasonable minimum take levels?

A. Staff's general concern appears to be based on a misunderstanding arising because of an incomplete data response, which PacifiCorp has since corrected. Staff correctly notes that the fueling budget used to inform CSA negotiations looks at generation forecasts 10 years into the future. But Staff claims that a discovery response indicates that the "generation forecasts used to support minimum take decisions [in] the new coal contracts do not look more than [redacted] years into the future."[15] This is incorrect. When negotiating a new CSA, the Company looks at the forecasted generation for the entire term of the contract, not just [redacted].[16] The Company's corrected discovery response includes all the data that was used to inform the negotiation of the new CSAs, which covered the full term of the proposed agreements.[17]

Q. How does the Company develop the fueling budget that is used to inform CSA negotiations?

A. PacifiCorp prepares generation forecasts as a part of its budget and planning forecasts relying on the most accurate and up-to-date information available. To prepare the generation forecast estimates, the Company considers many factors including historical usage patterns, sales and load forecasts, market prices, changes in available generation, and reliability requirements.

PacifiCorp's finance department calculates net power costs (NPC) over the

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[15] Staff/700, Anderson/11.
[16] The Company has supplemented its response to DR 71 to clear up the misunderstanding created by its original response.
[17] Confidential Exhibit PAC/601, 1st Revised Response to OPUC Data Request 71.

10-year business planning horizon based on projected data using the GRID. The overall fueling budget is developed by obtaining the thermal availability including planned maintenance, variable operation and maintenance unit costs, minimum load levels and heat rate input/output curves from thermal plant management. Incremental fuel costs and minimum take constraints are obtained, including volumes available at those incremental prices. PacifiCorp loads the data into GRID and runs the model using these inputs. These results are reviewed for reasonableness by comparing them to expected targets based on historical coal generation volumes adjusted for forecasted changes in load, anticipated system resources, renewables, and plant retirements.

Q. How do you respond to Staff's second concerns regarding inclusion of economic cycling in the generation forecast?

A. As discussed further below, the economics of the Dave Johnston and the operational realities Craig facilities make economic cycling not beneficial. Mr. MacNeil addresses how PacifiCorp considered economic cycling for the Hunter CSA in his testimony.

<u>Dave Johnston, Hunter, and Craig</u>

Q. Did Staff examine the minimum take levels in the new CSAs included in this case?

A. Yes. Staff's testimony addresses new CSAs at Dave Johnston, Hunter, and Craig.

Q. What did Staff conclude regarding the Dave Johnston CSAs?

A. Staff correctly points out that the new CSAs have a [redacted] term but Staff incorrectly claims that PacifiCorp negotiated the minimum take provision using a one-year forecast of expected fuel burns for the plant.[18] As explained above, in fact, PacifiCorp used a [redacted] forecast of expected burns, consistent with the term of the contracts and therefore performed the exact analysis Staff recommends. The minimum take levels included in the new CSAs represent [redacted] of the forecasted generation of 2022 test period. For 2022 all coal under contract represents [redacted] of the forecasted generation.

Q. Did PacifiCorp consider economic cycling in its forecasts used to negotiate the new Dave Johnston coal supply agreement?

A. No. Dave Johnston is the Company's lowest cost generation resource and is unlikely to ever be economically cycled off.

Q. What did Staff conclude regarding the new Craig CSA?

A. As explained above, staff incorrectly concluded that the Company used a one-year fuel burn forecast to negotiate a five-year CSA.[19] In fact, the Company used forecasted generation from the most recent 10-year plan which covered the entire term of the new coal supply agreement The minimum take levels included in the new CSAs represent approximately [redacted] of the forecasted generation.

Q. Did the Company consider economic cycling when forecasting the generation for purposes of negotiating the Craig CSA?

A. No. Craig is a jointly owned plant and therefore the Company cannot, on its own, economically cycle the units at the plant. The decision to economically cycle each unit depends on factors that are unique to each owner. Therefore, working with joint

[18] Staff/700, Anderson/15-16.
[19] Staff/700, Anderson/17.

owners to predict economic cycling would be complex, time-consuming, and non-conclusive. Each owner has different economic needs and load obligations, so coordinating economic cycling with other owners is not practical. Therefore, it would have been unrealistic to assume economic cycling in the generation forecast because it cannot occur in actual operations.

Q. Staff also asked PacifiCorp to explain why it agreed to be bound to a minimum take level at a mine where it is one of the owners, instead of agreeing to divide its share of costs over the tons of coal it actually needs in a given year."[20] How do you respond?

A. Like any other mine, the Trapper mine that provides coal to Craig needs a defined minimum tonnage volume commitment in order to adequately plan and execute an optimized least cost mine plan. The new Trapper CSA was developed with this concept in mind and was negotiated with the other Trapper owners and the Trapper mine. The CSA calls for and requires each Trapper mine owner to take their respective ownership share of the annual nominated tonnage. The annual nomination is required for the preparation of the annual mine plan and budget, which is subject to approval by PacifiCorp along with the other Trapper owners. By design, the CSA was negotiated with a very flexible range of tonnage regarding the annual minimum, base, and maximum tonnage levels. As such, PacifiCorp along with the other mine owners decide each year what the appropriate tonnage nomination level will be. Furthermore, the CSA has language which allows for the annual tonnage nomination

[20] Staff/700, Anderson/17.

to be set outside of the annual minimum and annual maximum ranges if needed, based upon mutual agreement by the Trapper owners and the mine.

Q. Do the 2022 forecasted burn levels at Dave Johnston or Craig exceed the minimum take levels of the new CSAs?

A. Yes. Staff agrees that for the 2022 TAM, "GRID dispatched [Dave Johnston and Craig] at or above 2022 minimum take levels based on economics," which "reassures Staff that the 2022 minimum take levels in these contracts were set somewhat appropriately for 2022[.]"[21] But Staff remains concerned that the "minimum take levels could eventually become binding constraints" and recommends that the Commission remove the minimum take assumptions for Dave Johnston and Craig going forward.[22]

Q. How do you respond to Staff's forward-looking adjustment?

A. Staff's adjustment is based on its misunderstanding of how the Company forecasts coal consumption for purposes of negotiating minimum take levels, as discussed above. Because the Company's methodology conforms to Staff's recommendation, there is no basis for Staff's proposed adjustment.

Q. Did Staff have any concerns over the minimum take level included in the new Hunter CSA?

A. No. Staff reviewed the Company's analysis underlying the CSA negotiations and proposed no adjustment.[23] Mr. MacNeil's testimony provides additional detail regarding the analysis used to support the Hunter CSA negotiations.

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[21] Staff/700, Anderson/17.
[22] Staff/700, Anderson/17.
[23] Staff/700, Anderson/16.

Q. Did the Company's analysis used to support the Hunter CSA differ from that used to support the Dave Johnston and Craig CSAs?

A. Yes, because the coal supply arrangements for Dave Johnston and Craig differ from Hunter. As discussed above, Dave Johnston is supplied by the relatively liquid PRB market and the CSAs represent a significantly smaller commitment. Unlike Hunter, where the new CSA represents the full plant requirements, the new Dave Johnston CSAs represent roughly [redacted] of the forecasted generation of 2022 test period. For 2022 all coal under contract represents [redacted] of the forecasted generation. The CSA for the Craig plant is also a smaller commitment because of the flexibility afforded under the contract, as discussed above.

Q. Staff also recommends that the Company improve its forecasting methodology and then hold stakeholder workshops regarding the improved methodology before filing the 2023 TAM.[24] How do you respond to this recommendation?

A. PacifiCorp does not agree that its methodology needs to be improved. As discussed above, the Company's methodology conforms with Staff's recommendations. To the extent that Staff and stakeholders want a better understanding of the methodology, the Company is not opposed to additional workshops before filing the 2023 TAM, as Staff requests.

<u>Huntington</u>

Q. Please provide an overview of the Huntington CSA.

A. The Company negotiated the Huntington CSA in 2014 and 2015 and executed the contract in 2015. The CSA's term extends to 2029. As explained in the extensive

[24] Staff/700, Anderson/13.

record in docket UM 1712, the Huntington CSA was a critical element of the Company's decision to close the Deer Creek mine because without a reliable coal supply for the plant, the Company could not have closed the mine. The Commission determined at the time that closing the mine provided significant customer benefits.[25]

Q. Has the Commission allowed recovery of costs incurred in accordance with the Huntington CSA in prior TAMs?

A. Yes. The Huntington CSA was first included in Company's 2016 TAM and the costs incurred under the CSA have been recovered in every subsequent TAM, largely without controversy.

Q. Please describe Staff's concerns over the Huntington CSA.

A. Staff is concerned that when the Company negotiated the Huntington CSA in 2015, it relied on a "short-sighted generation forecast."[26] Staff claims that PacifiCorp must demonstrate in this TAM that the minimum take levels included in the Huntington CSA are prudent or they should be eliminated for purposes of NPC modeling.[27]

Q. How do you respond to Staff's recommendation that the Commission review the prudence of the Huntington CSA in this year's TAM?

A. First, the Commission has already reviewed the Huntington CSA and found it prudent. As discussed above, in the 2017 TAM, CUB challenged the prudence of the Huntington CSA based on the inclusion of a minimum-take provision. The Commission rejected CUB's argument and found that PacifiCorp was not imprudent.[28] Staff's recommendation in this docket is therefore improper because its

[25] *See* Order No. 15-161 at 4.
[26] Staff/700, Anderson/20.
[27] Staff/700, Anderson/20.
[28] Order No. 16-482 at 9.

recommendation represents a significant and troubling departure from the Commission's well-established prudence standard.

Q. How does Staff's recommendation here deviate from the Commission's standard prudence review?

A. Although I am not a lawyer, it is my understanding that the prudence of a utility's decision "is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness."[29] It is also my understanding that once the Commission determines that a multi-year contract, like a CSA, is prudent based on what the utility knew or should have known, the Commission does not generally re-assess the prudence of the decision to enter into a multi-year contract every year based on changing circumstances that were not known when the utility decision was made.

Here, Staff's recommendation does not question whether the Company's implementation of the CSA is prudent. Rather, Staff questions the Company's decision to execute the agreement in the first place. Staff's recommendation amounts to a request that the Commission second guess its earlier prudence determination and decision to allow recovery of costs under the Huntington CSA six years into the contract term. The Company executed the Huntington CSA in 2015. The costs associated with the Huntington CSA have been included in customer rates since the 2016 TAM. This means that the Commission has authorized recovery of the costs

[29] *In the Matter of PacifiCorp, dba Pacific Power, Request for General Rate Revision*, Docket UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).

incurred under the CSA since 2016 and the Commission would not have authorized recovery of the costs incurred pursuant to the CSA if they were imprudent.

Q. Does Staff acknowledge that the Commission has previously allowed the Company to recover prudently incurred costs pursuant to the Huntington CSA in prior TAMs?

A. Yes. Staff agrees that the Commission has "approved power costs with the full minimum take level at Huntington in the past[.]"[30] But Staff claims that "in this year's TAM" it became clear that the minimum take levels included in the contract—which were negotiated in 2014 and 2015—should have been lower. Staff does not point to facts that the Company knew or should have known in 2014 and 2015. Staff's recommendation is therefore a clear-cut example of impermissible hindsight review.

Q. In docket UM 1712, the Company agreed that parties would have the opportunity to challenge the prudence of liquidated damages if they were incurred. Isn't that all that Staff is doing here?

A. No. Staff is not arguing that PacifiCorp's contemporaneous actions or decisions are imprudent, which is the type of prudence review contemplated by the Company's testimony in docket UM 1712. Rather, Staff is arguing that the decision to execute the CSA was imprudent even though the Commission has already rejected that argument in the 2017 TAM and found that the costs incurred in accordance with the CSA were prudently incurred.

In addition, Staff's recommendation here ignores the substantial customer

[30] Staff/700, Anderson/23.

benefits that have accrued as a result of the decision to close the Deer Creek mine, which could not have been achieved without the Huntington CSA.

Q. What information did the Company consider when it negotiated the minimum take levels in the Huntington CSA?

A. PacifiCorp looked at the forecasted generation for the remaining life of the Huntington plant. This information has been provided as a supplemental response to a data request which shows the output from GRID that the Company used for the negotiated minimum take levels in the Huntington CSA. When the Company negotiated the Huntington CSA, the minimum take level represented approximately [redacted] of the forecasted plant generation developed using the information available in 2014 and 2015 when the Company negotiated and executed the CSA. This data response is attached to my testimony as Confidential Exhibit PAC/602.

Q. Staff claims that the Company's 2014-2015 analysis should have considered a long-term generation forecast over the term of the contract that considered the long-term resource buildout in the Company's most recent IRP.[31] How do you respond to this claim?

A. As noted above, the Company looked at the forecasted generation for the remaining life of the plant and the analysis specifically accounted for the resource acquisitions included in the preferred portfolio from the Company's most recent IRP.

[31] Staff/700, Anderson/20-21.

Q. Staff also claims that the 2014-2015 analysis should have considered the possibility of economic cycling of Huntington.[32] Would that have been a reasonable assumption at that time?

A. No. When the Company developed the long-term generation forecast used to negotiate the Huntington CSA, the Company was not economic cycling its coal plants because market price forecasts at the time showed it was not economic to do so.

Q. Staff recommends removing the minimum take requirement for Huntington in this and all future TAMs "unless the Company can prove that its analysis used to negotiate minimum take levels was prudent."[33] How do you respond?

A. The Company disagrees with Staff's recommendation. The Commission already determined that the Huntington CSA was prudent and the costs incurred under the CSA have been included in rates for many years. Staff did not previously object to the prudence of the contract and cannot now demand that PacifiCorp demonstrate the prudence of a contract that is already included in customer rates.

__**Wyodak**__

Q. Staff testifies that the Company's NPC forecast inexplicably models the fuel burned at the Wyodak plant at 20 percent below the contract minimum.[34] Is this accurate?

A. No. The CSA for the Wyodak plant does obligate PacifiCorp to purchase a minimum of [redacted]

[32] Staff/700, Anderson/21.
[33] Staff/700, Anderson/22.
[34] Staff/600, Fox/31.

[redacted] PacifiCorp did not use a minimum purchase requirement for the TAM.

IV. RESPONSE TO CUB

Hunter

Q. Please describe PacifiCorp's recently executed CSAs for the Hunter plant.

A. As described in more detail in my direct testimony, the Company executed two new CSAs for Hunter. [redacted]. Both agreements have minimum take provisions, consistent with industry standards. The minimum take provisions are considerably less than the Company's forecasted generation over the term of the CSAs.

Q. Please describe CUB's concerns over the new Hunter CSAs.

A. CUB is concerned that the minimum take provisions in the Hunter CSAs are too high.[35] In particular, CUB claims that the minimum take volumes represent

[35] CUB/100, Jenks/11-12.

[redacted] of expected generation, which CUB claims leaves little room for reduced generation.

Q. How do you respond to CUB's concern over the minimum take level in the new Hunter CSAs?

A. CUB's concern is based on a mistake made in the initial filing. The [redacted] figure represents the PacifiCorp share of the generation not the total Hunter generation. The minimum purchase amount is for the total (100 percent) plant generation. A mistake was made in the initial filing that only included the PacifiCorp share of the forecasted generation. This error will be fixed as part of the NPC update to include the forecasted generation of the Hunter plant joint owners. This updated forecast shows that the minimum take volumes represent [redacted] of the expected generation. As described below, however, when compared to the corrected NPC update generation forecast, Hunter's minimum take level is not as high as CUB claims and is reasonable for the new CSAs.

Q. Does CUB propose an adjustment related to the new Hunter CSAs in this case?

A. No. Although CUB indicates that they may propose an adjustment in future TAMs.[36]

Q. Do you have any concerns with CUB's approach to reviewing the prudence of multi-year CSAs?

A. Yes. As discussed above, the Company is concerned that parties are recommending ongoing, annual prudence review of multi-year contracts based not on how PacifiCorp operates under the contract but instead whether it was prudent to execute the contract in the first place. For the same reasons that the Company objects to

[36] CUB/100, Jenks/12.

Staff's proposed adjustment related to the Huntington CSA, the Company objects to annual prudence reviews for the Hunter CSAs.

Huntington

Q. Please describe CUB's concern related to the Huntington CSA.

A. CUB agrees that the Company was prudent to execute the long-term CSA in 2015. But CUB believes that the Company should conduct an analysis to determine whether the contract is leading to uneconomic dispatch of the plant, whether that is related to new environmental laws and regulations, and whether it is in the customer's interests to invoke the contract termination process.[37]

Q. Does the Huntington CSA allow the Company to terminate the agreement if environmental laws or regulations affect the economics of the plant?

A. Yes, generally speaking. [redacted]

[redacted]

In docket UM 1712, the Company explained:

> The Company negotiated Article 8 in recognition of the uncertainty now inherent in the environmental regulation of coal generation. The Company's intent was to secure broad flexibility in responding to the impact of the changing environmental regulations or

[37] CUB/100, Jenks/14.

> settlements on Huntington, including the ability to terminate the CSA without liquidated damages if future changes in applicable environmental requirements affect the Company's ability to operate Huntington as a coal-fired facility . . . The Company intended Article 8 to address a scenario where an environmental requirement made the continued operation of the plant as a coal-fired facility uneconomic.[38]

Q. CUB points to Oregon Senate Bill (SB) 1547, which phases out coal plants and requires 50 percent renewables, and the 100 percent clean electricity laws passed in Washington and California as examples of environmental regulation that might provide a basis for the Company to terminate the Huntington CSA.[39] Do you agree?

A. No. While CUB's interpretation of Article 8 is generally consistent with the Company's, given the information provided, the Company does not agree that it would have the right to terminate the Huntington CSA based on the environmental laws cited by CUB. The effects of an environmental regulation must be more directly applicable to the Huntington plant; the potentially indirect impact on Huntington from legislation like SB 1547 is not a basis to seek termination of the CSA. To the extent the Company can establish a clear connection between an implemented regulation and its effects on the operation of the Huntington plant, including possibly economic affects, then the Company believes the exercise of the Article 8 rights would be warranted and defensible. The potential impact resulting from the legislation cited by CUB, however, appear to be largely speculative and remote, and lack any direct, causal link between the environmental regulation and the effects on the plant. As

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[38] Docket No. UM 1712, PAC/500, Crane/6.
[39] CUB/100, Jenks/14-15.

such, the resultant effects, if any, would likely be an indefensible basis to trigger the rights provided for under Article 8.

Q. At this time, are you aware of any other current and anticipated environmental statutes or regulations that might allow the Company to terminate the coal supply agreement pursuant to Article 8?

A. No.

Q. CUB recommends that "the Company should conduct an analysis to determine whether the contract is leading to uneconomic dispatch of the plant, whether that is related to new environmental laws and regulations and whether it is in the customers' interest to invoke the contract termination provisions."[40] Do you agree with this recommendation?

A. No, because CUB's analysis is unnecessary at this time and would result in an unjustified cost to customers. The Company is unaware of any current or emerging environmental regulations that have or would have a direct economic impact on or otherwise impact the Company's ability to burn coal at the plant. While new environmental regulations have been enacted, like SB 1547, that could possibly have an effect on the economics of the plant, the Company is unaware of any environmental regulation with an indirect connection to the plant where an adverse effect upon the plant's economics could be substantiated.

Moreover, the Company's IRP process is designed to analyze the economics of the plants and determine appropriate plant lives. The 2021 IRP is currently being

[40] CUB/100, Jenks/14.

prepared and is a more appropriate venue for studying the ongoing economics of the Huntington plant.

Finally, CUB's perspective is overly simplistic and impractical, and fails to take into account the complexities of the coal markets. The notion that the Company should terminate the existing agreement assumes that the Company will be able to replace the existing supplier, [redacted], with other supplier(s) that can provide the quantity and quality of coal required to operate the plant. It further assumes that the Company will be able to replace the coal with lower cost coal and improve the economics of operating the plant. None of this is certain because this notion fails to consider the illiquid Utah coal market. [redacted] is the largest supplier of low sulfur coal in Utah. The Company is purchasing Utah's other low sulfur coal supplier's ([redacted]) production for the Hunter plant under a four-year coal supply agreement that was executed in 2020. CUB recommends that the Company consider terminating the Huntington coal supply agreement based on environmental laws with little connection to the Huntington plant's economics and then immediately engage in negotiations with the same supplier for the replacement supply. In addition to damaging the financial viability of one of the few remaining coal suppliers able to supply the Company's Utah facilities, this action is risky and may not improve the economics of the plant or be in customers' interest.

Q. Under what circumstances would you recommend exercising Article 8 of the Huntington CSA?

A. There may be future circumstances that would properly lead the Company to terminate the coal supply agreement pursuant to Article 8. These circumstances would include a new environmental rule or regulation where a negative economic effect on PacifiCorp's system or the Huntington plant could be substantiated and where termination could be demonstrated to be in the customers' interest.

V. RESPONSE TO ALLIANCE OF WESTERN ENERGY CONSUMERS (AWEC)

Q. AWEC claims that the Company has consistently overstated the material and supply expense for BCC and therefore recommends a reduction of approximately $3.1 million dollars (total-company) based on his analysis of the historical variances between forecasted and actual material and supply expenses.[41] Do you agree with AWECs recommendation?

A. No. AWEC's recommendation was formulated by dividing BCC material and supply expenses by tons delivered. AWEC compared material and supply costs included in TAM filings to actual material and supply costs for 2018 through 2020. This evaluation approach is inaccurate, misleading, and inappropriate for the following reasons:

First, BCC material and supply costs include expenditures incurred to not only produce and deliver coal but also to complete final reclamation activities. During 2018 through 2020, BCC moved [redacted][42] or [redacted][43] more final reclamation cubic yards than assumed in the referenced TAM filings. Dividing material and supply costs by tons delivered and not excluding costs incurred for final reclamation activities provides inaccurate, misleading information.

[41] AWEC/100, Mullins/23.
[42] Confidential PAC/603, tab "M&S".
[43] Confidential PAC/603, tab "M&S".

Second, AWEC's analysis highlighted that actual material and supply costs were [redacted][44] *lower* than estimates included in TAM filings for 2018 through 2020 and failed to acknowledge that other actual costs were higher than estimates included in the referenced TAM filings. As an example, costs for outside services alone for 2018 through 2020 are [redacted][45] higher than estimated in the filings. Cherry picking some costs that AWEC claims are overstated, while ignoring offsetting costs that are understated is unreasonable.

Third, AWEC's analysis assumes royalties would be assessed on the total material and supply cost per ton amount at a rate associated with only the surface mine. Royalties assessed on coal delivered from federal and state lease areas are subject to a cost-plus-return methodology, not coal delivered from private lease areas. Furthermore, the appropriate rate for coal extracted using surface mining methods is [redacted][46] and the appropriate rate for coal extracted using underground mining methods is [redacted].[47]

Fourth, AWEC multiplied its recommended materials and supply cost per ton amount by PacifiCorp's portion of tons delivered and then incorrectly multiplied the dollar amount by PacifiCorp's portion again.

Q. Have you compared actual Jim Bridger plant received coal costs from BCC to estimates included in recent TAM filings?

A. Yes. During 2018 through 2020, Jim Bridger plant coal received costs from BCC expressed on a cost per one million British thermal units (MMBtu) basis are

[44] Confidential PAC/603, tab "M&S".
[45] Confidential PAC/603, tab "M&S".
[46] Confidential PAC/603, tab "AWEC Calculation".
[47] Confidential PAC/603, tab "AWEC Calculation".

[redacted][48] less than rates estimated in the referenced TAM filings. It is important to note Bridger Coal delivered [redacted][49] more coal to the Jim Bridger plant during this three-year period which contributed to the cost reduction. However, during 2016 through 2020, Jim Bridger plant coal received costs from BCC expressed on a cost per MMBtu basis are only [redacted][50] less than costs estimated in the TAM filings. BCC delivered [redacted][51] less coal during this five-year period.

Q. Because BCC provides only a portion of Jim Bridger plant's fueling requirement, have you compared estimated Jim Bridger plant received coal costs in TAM filings to actual received coal costs at the plant?

A. Yes. During 2018 through 2020, Jim Bridger plant received fuel costs expressed on a cost per MMBtu basis are [redacted][52] less than rates estimated in the referenced TAM filings. It is important to note Jim Bridger plant received [redacted][53] more coal during this three-year period, which contributed to the cost reduction. During 2016 through 2020, Jim Bridger plant received fuel costs expressed on a cost per MMBtu basis are [redacted][54] less than rates estimated in comparative TAM filings. Actual coal receipts at the plant are [redacted][55] less than estimated in TAM filings during 2016 through 2020.

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[48] Confidential PAC/603, tab "Summary".
[49] Confidential PAC/603, tab "Summary".
[50] Confidential PAC/603, tab "Summary".
[51] Confidential PAC/603, tab "Summary".
[52] Confidential PAC/603, tab "Summary".
[53] Confidential PAC/603, tab "Summary".
[54] Confidential PAC/603, tab "Summary".
[55] Confidential PAC/603, tab "Summary".

Q. Because the TAM is a forward-looking mechanism, how are net power costs differentials between forecast and actuals reconciled in Oregon?

A. The Company relies on its Power Cost Adjustment Mechanism (PCAM) to true-up differences between net power costs. But the PCAM has a $30 million deadband so only cost differentials outside the deadband are subject to true-up.

Q. Would PacifiCorp object to implementing an adjustment mechanism in Oregon that would enable estimated net power costs to be trued-up to actual net power costs on an annual basis?

A. No.

VI. RESPONSE TO SIERRA CLUB

New CSAs and Minimum Take

Q. Sierra Club recommends that the Commission review and determine the prudency of new CSAs in the TAM.[56] Do you agree with this recommendation?

A. Yes. PacifiCorp agrees that it is reasonable for the Commission to assess the prudence of a new CSA in the TAM, although the Company disagrees with Sierra Club's specific recommendations regarding what the prudence review should consider. Moreover, as discussed above, the prudence review for CSAs should be performed consistent with the Commission's long-established practice and occur in the first TAM where costs will be incurred under the agreement. The Commission should not engage in annual reassessments of the Company's decision to enter into a new CSA based on changing market conditions occurring subsequent to the decision to enter the CSA that were not reasonably foreseeable at the time.

[56] Sierra Club/100, Burgess/35.

Q. In the context of reviewing new CSAs, does Sierra Club provide any specific recommendations?

A. Yes. Sierra club recommends:

- minimum take levels should be set to 50 percent or less of projected consumption;
- PacifiCorp should only enter into short-term coal supply agreements, ideally no more than 1-2 years; and
- all coal supply agreements should include renegotiation provisions to avoid or reduce minimum take provisions if certain conditions arise.[57]

Q. Are Sierra Club's recommendations reasonable and in the best interests of customers?

A. No. Sierra Club's recommendations do not consider the commercial realities associated with contracting for coal supply in the illiquid markets that supply all of PacifiCorp's thermal coal fleet plants, excluding the Dave Johnston plant. Even if PacifiCorp could obtain coal supplies under the terms Sierra Club proposes, the associated costs would be much higher, a consideration that he ignores.

Sierra Club's recommendations would also make it impractical for coal suppliers to obtain capital to invest in mine coal production for future contracts, reducing future participation in requests for proposals and further weakening the illiquid coal markets PacifiCorp depends on for fuel supply. These recommendations would create greater risk of securing reliable fuel for PacifiCorp plants' requirements and increase the cost of fuel. In addition, allowing only 50 percent of the forecasted

[57] Sierra Club/100, Burgess/3, 35, 45, 48.

coal supply to be under contract in increasingly illiquid markets would present an unacceptable risk of supply for customers, especially given the reliability issues already facing the region. This issue is discussed in more detail in Mr. Schwartz's testimony.

In summary, because Sierra Club's recommendations would increase both coal supply risk and costs, they are not in the best interests of customers.

Q. In contrast to Sierra Club's recommendations, does PacifiCorp's current coal supply strategy allow it to reduce risks and costs whenever possible?

A. Yes. For example, the Hunter plant was previously supplied under a single long-term agreement. As explained in more detail below, PacifiCorp recently negotiated two Hunter CSAs. The agreements resulted from a competitive solicitation process and resulted in lower fuel costs. The first agreement was selected as the least-cost, least-risk contract with a supplier PacifiCorp had not used in the past. This allowed the limited market which supplies the Hunter plant to expand and ultimately resulted in increased coal supply availability and market competition. The second contract negotiations benefited from the increased competition, which resulted in favorable pricing for the Hunter plant's fueling needs in comparison to previous contracted pricing. Mr. Schwartz also addresses the prudence of the new Hunter coal supply agreements in more detail, refuting Sierra Club's criticism of the agreements for failing to meet his minimum take and contract length recommendations.

Q. PacifiCorp procures fuel for the Dave Johnston plant from a liquid market. Does PacifiCorp employ a different coal contracting strategy for this plant?

A. Yes. PacifiCorp capitalizes on the opportunity to purchase coal in the liquid Powder

River Basin market. PacifiCorp secures contracts in a ladder approach, staggering contracts to ensure adequate coal requirements during the current year while allowing flexibility in the future. This portfolio approach has provided customers with some of the lowest coal costs in the fleet.

Q. Sierra Club recommends that "utilities should seek to avoid entering contracts where the minimum take provisions exceed 50 percent of projected consumption."[58] Is this recommendation consistent with industry practices?

A. No. In a response to a discovery request Mr. Burgess indicated that he based his opinions on his experience and professional judgement.[59] Despite his referenced experience reviewing other utility fuel procurement plans, he did not name or assert that there were any other utilities whose procurement plan restricted entering contracts with minimum take requirements more than 50 percent of expected burn for the upcoming year.

As explained by Mr. Schwartz, it is unheard of for a coal buyer willing to have as little as 50 percent of its projected burn under contract for the upcoming year because it would be highly risky for a utility to have so little coal purchased under contract for the upcoming year.

Q. Sierra Club asks the Commission to review whether PacifiCorp's coal contracts contain renegotiation provisions that would allow it to avoid or reduce minimum take provisions if certain conditions arise. Please respond.

A. PacifiCorp has been successful in negotiating coal supply agreements that contain

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[58] Sierra Club/100, Burgess/45.
[59] *See* Exhibit PAC/502.

provisions that reduce minimum take obligations when certain conditions are triggered under the agreements. These conditions include environmental requirements, force majeure events, and coal quality excursions. These specific provisions are outlined within the respective coal supply agreements.

Q. Has PacifiCorp exercised a contract provision that reduced a minimum take volume in the past?

A. Yes. PacifiCorp exercises these provisions in both the coal and transportation agreements whenever conditions warrant.

Q. Can you provide an example when PacifiCorp exercised one of these contract provisions that reduced a minimum take volume in the past?

A. Yes. Based on an environmental triggering event, PacifiCorp was able to lower the contractual annual minimum tonnage requirement from [redacted] tons to [redacted] tons under the existing coal supply agreement at the Naughton plant.

Q. Sierra Club criticizes PacifiCorp's generation forecasts used for CSA negotiations.[60] Please explain Sierra Club's specific concerns.

A. Sierra Club focused on the negotiations for the new Dave Johnston, Craig, and Hunter CSAs. Sierra Club claims that the Company has overestimated generation for these three plants.

Q. Do you agree?

A. No. Even with the execution of the two Dave Johnston's CSAs, open positions exist for the plant beginning in years 2023 and beyond, which does not indicate the generation forecast is excessive relative to the minimum take levels included in the

[60] Sierra Club/100, Burgess/36.

new CSAs. As for the two Hunter CSAs, the negotiated minimum annual tonnage requirements are prudent and reasonable based upon the needs of the plant, as described in more detail in Mr. MacNeil's testimony. Finally, the Trapper CSA, which supports PacifiCorp's requirements at the Craig plant, has a wide range of tonnage flexibility built into the CSA based upon PacifiCorp's fueling requirements for its share of Units 1 and 2 of the Craig Station, as discussed above.

Q. Has Sierra Club presented this same argument in other jurisdictions?

A. Yes. In PacifiCorp's 2020 Energy Cost Adjustment Clause (ECAC) proceeding in California, Sierra Club argued that, "PacifiCorp has a coal oversupply problem, . . . attributable to erroneous coal burn forecasts based on low dispatch prices and long-term coal supply contracts with minimum take requirements."[61] The CPUC rejected Sierra Club's argument in its entirety and found that there was no evidence that any of PacifiCorp's specific coal supply agreements were imprudent.[62]

Q. Sierra Club questions the assumptions PacifiCorp used to estimate coal prices for fuel supplies that are current uncontracted, i.e., open positions.[63] Please explain Sierra Club's concern.

A. Sierra Club claims that the Company has assumed that the coal supply that will be used to fill the open positions for 2022 will be subject to minimum take requirements.[64] Sierra Club further claims that this is a departure from PacifiCorp's business practices.

[61] 2020 ECAC, D.20-12-004 at 21 (Dec. 7, 2020).
[62] 2020 ECAC, D.20-12-004 at 24.
[63] Sierra Club/100, Burgess/3.
[64] Sierra Club/100, Burgess/39.

Q. How do you respond to Sierra Club's claims?

A. Sierra Club is correct that the Company has assumed that the open position for 2022 will be filled by CSAs with minimum take provision for the Naughton plant and the Black Butte CSA for the Jim Bridger plant (which is discussed above). These plants have limited supply options. The Company expects the suppliers for these plants to require future CSAs to include a minimum purchase obligation as is typical of most coal contracts.

Coal purchased for consumption at Dave Johnston will be purchased on a take-or-pay basis as is typical of PRB coal contracts. The Company will control the risk of oversupply by closely evaluating the need for any portion of the open position prior to executing a new agreement.

Sierra Club is incorrect that the assumptions used in the TAM are a departure from PacifiCorp business practices. Each plant is different and budget assumptions are plant specific in nature. Assumptions that are made for one plant do not necessarily translate to the other plants in the fleet.

Q. Sierra Club recommends that the Commission approve costs associated with open positions on an interim basis and require a true-up once the contracts are finalized and submitted for the Commission's review.[65] Is this a reasonable recommendation?

A. No. Many NPC elements are forecast in the TAM without true-up to actuals. Singling out CSAs for unique treatment is therefore unreasonable. The true-up to

[65] Sierra Club/100, Burgess/41.

actuals takes place in the PCAM. However, because of the dead band and sharing bands, there has not been a true-up to actuals in the last 13 years of the PCAM.

Hunter

Q. Please describe Sierra Club's concern over the new Hunter CSAs.

A. Sierra Club argues that the minimum take provisions are imprudent.[66] Sierra Club therefore recommends that shareholders, not customers, pay for any future minimum take penalties that arise from the Hunter CSAs.

Q. Does any other party challenge the minimum take provision in the Hunter CSAs?

A. No. Staff and CUB reviewed the CSAs and both agree that the minimum take provisions are reasonable for the 2022 TAM.[67]

Q. What is the basis for Sierra Club's proposed adjustment?

A. Sierra Club claims that PacifiCorp's forecasted generation for Hunter is too high relative to the minimum take level.[68]

Q. How do you respond to Sierra Club's claims?

A. Sierra Club's testimony is misleading and erroneous. The minimum take obligations under the new Hunter CSAs are equal to [redacted] of the three-year average (2021 – 2023) burn under the "high" burn forecast and [redacted] of the [redacted] average burn under the "low" burn forecast. Compared to the "expected" burn forecast, the minimum take requirements are [redacted] of the [redacted] projected "average" quantity needs. For the Company to be over-contracted for coal, the coal burn at

[66] Sierra Club/100, Burgess, 3, 43-46.
[67] Staff/700, Anderson/16; CUB/100, Jenks/12.
[68] Sierra Club/100, Burgess/42-43.

Hunter would have to be at least [redacted] below the "low" burn forecast and 34 percent below the "expected" burn forecast, not just for one year – for all [redacted]. Thus, it is extremely unlikely that the Company has entered minimum take obligations that will be below the burn requirements at the Hunter plant.

Q. Sierra Club claims that the minimum take obligation is approximately [redacted] of the total generation forecast for Hunter.[69] Is that correct?

A. No. As explained above, this percentage represents the PacifiCorp share of the contract. A mistake was made in the initial filing that only included the PacifiCorp share of the forecasted generation. This error will be fixed as part of the NPC update to include the forecasted generation of the Hunter plant joint owners. This updated forecast shows that the minimum take volumes represent [redacted] of the expected generation. This decrease in forecasted generation was not a product of the must run setting.

Q. Sierra Club is also critical that the new Hunter CSAs last from [redacted], which Sierra Club claims limits the Company's flexibility.[70] How do you respond?

A. As discussed above, Sierra Club's recommendation for 1-2 year CSAs is unreasonable and contrary to standard industry practice. The term of the new Hunter CSAs provides reasonable flexibility to the Company, while balancing the need for a stable and secure fuel supply and a reasonable price.

[69] Sierra Club/100, Burgess/43.
[70] Sierra Club/100, Burgess/49.

Jim Bridger

Q. Please explain the Jim Bridger plant fueling plan and why it is reasonable.

A. The Jim Bridger plant is currently fueled by BCC and Black Butte Coal Company. BCC is a jointly owned subsidiary of the Jim Bridger plant owners (PacifiCorp and Idaho Power Company). Black Butte Coal Company is an unaffiliated, third-party coal supplier that is located near the Jim Bridger plant. With these two suppliers, PacifiCorp can fuel the Jim Bridger plant with a least-cost, least-risk fuel supply. This fueling plan also allows PacifiCorp to avoid the significant capital investment that would be required to fuel the Jim Bridger plant from other sources.

Q. Has the Commission previously addressed the fueling strategy for Jim Bridger?

A. Yes. Issues regarding PacifiCorp's fueling strategy for the Jim Bridger plant have been raised multiple times over the years, including in the dockets UE 264 (2014 TAM), UE 307 (2017 TAM), UE 323 (2018 TAM), UE 339 (2019 TAM), and UE 356 (2020 TAM), and the Commission has repeatedly affirmed the reasonableness of the Company's strategy.

Most notably, in 2018 PacifiCorp finalized the Long-Term Fuel Supply Plan for the Jim Bridger Plant. The plan was filed as part of the 2019 TAM.[71] As part of the 2019 TAM, PacifiCorp agreed to update the plan based on stakeholder feedback. The updated plan was then filed as part of the 2020 TAM[72] and no party objected to the fueling strategy laid out in the plan.

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[71] Docket No. UE 339, PAC/204.
[72] Docket No. UE 356, Exhibit PAC/201.

Q. Can you briefly summarize the customer benefits associated with PacifiCorp's partial ownership of BCC?

A. Yes. Ownership in BCC allows PacifiCorp to flex coal deliveries up or down to better align Jim Bridger plant delivered and consumed coal quantities. Mine ownership provides influence and leverage on the price the external coal supplier can charge, reduces coal supply delivery risk, improves the Jim Bridger plant's ability to match coal delivery and consumed quantities, and mitigates unfavorable impacts of significant, unexpected coal delivery changes.

Q. Has the Commission recognized the value that BCC provides to Oregon customers?

A. Yes. In the 2014 TAM, the Industrial Customers of Northwest Utilities (ICNU), the predecessor to AWEC, proposed a disallowance under OAR 860-277-0048, the Commission's lower of cost or market rule for affiliates. ICNU claimed that third-party coal from the Black Butte mine was lower priced than coal from BCC mine, so the BCC coal should be repriced based on the Black Butte contract.

The Commission rejected this adjustment, approving PacifiCorp's fueling strategy for the Jim Bridger plant as "fair, just and reasonable." Specifically, the Commission found there was no available lower-cost market alternative to replace BCC coal. The Commission was not persuaded that Black Butte coal would be available in the excess capacity required or that it would be less expensive than the BCC contract price for the period in question.[73] The Commission adhered to its

[73] *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387, at 5-7 (Oct. 28, 2013).

practice of evaluating BCC coal costs for whether they were objectively reasonable. The Commission found those costs reasonable in the 2014 TAM because while the BCC and Black Butte prices had fluctuated over the years, they had remained relatively stable when viewed over the long term. In addition, the Commission found there was scarce availability for lower-cost market alternatives to BCC coal.

The Commission addressed BCC again in the 2017 TAM, where ICNU and Staff challenged Jim Bridger fuel costs on the basis that BCC coal costs were higher than market alternatives, albeit this time with reference to coal from the PRB rather than the Black Butte mine. Staff argued the Company was imprudent in failing to consider market alternatives, while ICNU revived its arguments from the 2014 TAM regarding the lower of cost or market rule. The Commission rejected both sets of arguments, reaffirming the reasonableness of PacifiCorp's fueling strategy, including continued reliance on BCC coal.[74]

Q. Sierra Club testifies that the dispatch tier at the Jim Bridger plant is considerably lower than the costing tier.[75] Can you explain why?

A. Yes. At the Jim Bridger plant, the dispatch tier cost represents the incremental cost associated with procuring additional coal above the minimum mine plan volumes. For the Jim Bridger plant, the incremental cost is derived by evaluating production and cost differentials between two operating plans at BCC. BCC is a captive mining operation adjacent to the plant and can adjust coal production quantities to comply with reasonable changes in fuel requirements at the plant. In recent years, plant coal

[74] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482, at 5-8 (Dec. 20, 2016).
[75] Sierra Club/100, Burgess/50-51.

consumption has decreased and enabled BCC to balance coal production and required final reclamation activities. This ability to switch mining activities between coal production and reclamation has previously enabled the mine to utilize mine equipment and mine employees in a relatively efficient manner.

Q. How does BCC determine the incremental coal cost?

A. BCC typically develops costs for different mine plans to identify expected coal costs at differing targeted production levels. The cost differential between the plans is divided by the tonnage differential between the plans to determine BCC's expected incremental cost.

Q. Sierra Club conducts an analysis of the fixed costs at BCC based on information provided in a PacifiCorp data request. Does Sierra Club mischaracterize the information from that data request at the fixed cost components at BCC?

A. Yes. Sierra Club relies on information that was provided to them in Data Request 2.5. However, as was pointed out in Sierra Club Data Request 2.5, the table does not include other fixed costs that are embedded in labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs that are independent of coal production activities. Additionally, the majority of fixed labor costs, approximately [redacted], would be considered fixed because a core set of skills is required to enable the mine to respond to future potential coal demand increases and complete reclamation as required by federal and state regulations.[76] Mr. Staples, in his testimony, discusses how including these costs significantly undermines Sierra Club's analysis regarding dispatching Bridger at average cost.

[76] Sierra Club/112, Burgess/5-7.

Q. Has PacifiCorp made any changes to its calculation and use of the dispatch price at Jim Bridger since the 2021 TAM?

A. No. As Mr. Staples testifies, PacifiCorp's approach is the same in this case as in the prior TAMs.

Q. Does PacifiCorp agree with Sierra Club's assertion that Jim Bridger plant's dispatch tier price "should be nearly equal to the average or costing tier price" to be modeled in GRID?[77]

A. No, for the reasons described above.

Q. Has Sierra Club raised this argument before?

A. Yes. Sierra Club raised this identical argument in PacifiCorp's 2020 ECAC filing in California. In that case, the CPUC rejected Sierra Club's argument and approved PacifiCorp's use of incremental costs for Jim Bridger plant dispatch and found that the higher average costs used to forecast Jim Bridger's fuel costs were reasonable.[78]

Q. Do you agree with Sierra Club's position that PacifiCorp should only assume the supplemental price is in effect once the base quantity has been exhausted?[79]

A. No. This is just another way of arguing against the use of incremental costs for dispatch. Under Mr. Burgess' approach, customers would pay full BCC base costs but forgo the overall cost reductions associated with incremental coal dispatch, a key benefit of mine ownership. The net result would be higher costs paid by customers.

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[77] Sierra Club/100, Burgess/51.
[78] 2020 ECAC, D.20-12-004 (Dec. 7, 2020).
[79] Sierra Club/100, Burgess/62.

Q. Do you agree with Sierra Club's claim that the lack of a minimum take obligation should give PacifiCorp the flexibility to reduce its consumption at that plant substantially without a penalty?[80]

A. No. Although no minimum take penalties are incurred when BCC deliveries are flexed down, costs expressed on a unit cost basis increase. This is because "fixed" costs do not change when generation is reduced. Therefore, the Company has flexibility to reduce BCC deliveries, but that flexibility is not unbounded.

Q. Sierra Club acknowledges that "certain technical requirements and safety concerns" limit the Company's ability to flex down BCC production at the underground mine, but Sierra Club claims those limitations will not apply in 2022.[81] Is that correct?

A. The referenced technical concerns will not exist after the underground mine shutters coal production in January 2022 as assumed in the 2022 TAM filing. But that does not translate into the overall flexibility that Sierra Club implies.

Q. Sierra Club states that PacifiCorp does not take full advantage of the ability to flex down coal from BCC rather than risk minimum take penalties from Black Butte.[82] Is Mr. Burgess correct?

A. No. BCC has indeed flexed down coal deliveries as noted in the following table:

[80] Sierra Club/100, Burgess/51-52.
[81] Sierra Club/100, Burgess/54.
[82] Sierra Club/100, Burgess/53.

Bridger Coal Company
Jim Bridger Plant - PacifiCorp Portion

Description	2019 Actual	2020 Actual	2021TAM and June 2021 Fcst.	2022 TAM
Tons Delivered - 000's	[redacted]			
Annual Percent Change				

Q. Sierra Club claims that the Company's 2021 TAM modeling purposely avoided reducing BCC deliveries thereby triggering minimum take penalties for Black Butte coal.[83] Is that true?

A. Yes, but only in the hypothetical "average cost" model. The hypothetical "average cost" compliance filing assumed megawatt hours generated decreased by [redacted] from the direct 2021 TAM filing. As a result of this unplanned, hypothetical generation reduction, the average cost analysis assumed a minimum take penalty was incurred because of the existing Black Butte contractual obligation and the inability to reduce BCC Coal deliveries by [redacted]. A steady rate of mining is required at BCC's underground mine to avoid adverse geological issues that would negatively impact productivity rates, coal quality, operating costs and could create unsafe working conditions.

Q. Sierra Club argues that because the Company has not executed a CSA for Black Butte coal for 2022, it may not need to do so if it is economic to simply reduce generation at the Jim Bridger plant.[84] How do you respond to this argument?

A. As discussed above, BCC could not deliver the Jim Bridger plant's required coal by

[83] Sierra Club/100, Burgess/53.
[84] Sierra Club/100, Burgess/53.

itself. Given that Black Butte coal is lower price than the alternative, it is unclear why Sierra Club believes that the Company may not need to renew the Black Butte contract. Based on the preferred portfolio in the 2019 IRP and diminishing economically recoverable coal reserves at BCC, Black Butte remains an important fuel source to sustain the Jim Bridger plant projected generations levels. This is in line with the Jim Bridger Plant Long-Term Fueling Strategy. Additionally, Sierra Club themselves acknowledge that this is not "directly relevant" to this TAM.[85]

Q. Sierra Club also claims, without citation, that PacifiCorp previously represented that it must meet a base level of scheduled production at BCC every year, even though according to Sierra Club PacifiCorp "self-determines" the operations at the BCC mine.[86] Is this correct?

A No. First, PacifiCorp does not "self-determine" BCC production; BCC is managed by a committee of two members each from PacifiCorp and Idaho Power Company with equal voting rights. Second, a base level of schedule production is needed to maintain the mine and keep workforce to be able to complete the final reclamation work when mining operations cease.

Q. If a significant reduction in Jim Bridger plant generation were known in advance of critical decisions points, how would PacifiCorp respond to those diminished fueling needs?

A. Within reasonable limits, PacifiCorp, in conjunction with its partner, would alter BCC mine plans by adjusting shifts worked at the surface mine, redirect mining activities

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[85] Sierra Club/100, Burgess/68.
[86] Sierra Club/100, Burgess/54.

from coal production to reclamation when feasible, flex coal inventory levels, and seek to align future external contract volumes with the reduced generation forecast mitigating Jim Bridger plant fuel supply risks and costs. Of note, BCC's underground mine is projected to deplete existing coal reserves near year-end 2021.

Q. Sierra Club argues "it may be prudent for PacifiCorp to evaluate accelerated closure of the mine."[87] Mr. Burgess further states "the Commission should consider whether it would have been prudent for PacifiCorp to have considered this option well in advance of the 2022 TAM."[88] How do you respond?

A. First, as just noted, PacifiCorp is closing BCC's underground mine near year-end 2021. Second, PacifiCorp evaluated early closure of BCC in the Commission-acknowledged 2019 IRP and determined that it was a high cost fueling option and not in the public interest. Sierra Club participated in the 2019 IRP stakeholder process and is fully aware that PacifiCorp evaluated this option in the 2019 IRP.

Q. Sierra Club also argues that reclamation costs for BCC are not entirely fixed and recommends that the Commission consider the fixed nature of these costs and whether they should be recovered "given past management practices."[89] How do you respond?

A. Mr. Burgess acknowledges "that final reclamation costs are unavoidable"[90], comments reclamation costs in the 2022 TAM may be higher than they otherwise would have been if additional funds were collected in earlier years[91] and states "In

[87] Sierra Club/100, Burgess/55.
[88] Sierra Club/100, Burgess/55.
[89] Sierra Club/100, Burgess/57–58.
[90] Sierra Club/100/Burgess/57.
[91] Sierra Club/100/Burgess/57.

fact, it is possible that PacifiCorp is continuing to operate the Bridger mine merely to continue collecting reclamation contributions from ratepayers…"[92] First, final reclamation contributions are reviewed and recalculated concurrently with Bridger Coal's annual budget process. The calculation considers the trust funds beginning balance, projected trust fund earnings, withdrawals and contributions required to fund the reclamation obligation. PacifiCorp's trust fund contribution amounts are therefore based on the most current engineered mine plans and financial information available at the time. To suggest that additional funds should have been collected in earlier years with no analytical support would have been imprudent and contrary to statutory regulations. Second, Mr. Burgess' supposition that PacifiCorp is continuing to operate the Bridger mine merely to continue collecting reclamation contributions from ratepayers is not supported with any analysis or basis in fact. Sierra Club participated in the 2019 IRP stakeholder process and is fully aware that PacifiCorp evaluated early closure of BCC and determined that it was a high cost fueling option and not in the public interest.

Q. Does this conclude your reply testimony?

A. Yes.

[92] Sierra Club/100/Burgess/58.

REDACTED
Docket No. UE 390
Exhibit PAC/601
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

1st Revised Response to OPUC Data Request 71

July 2021

UE 390 / PacifiCorp
June 21, 2021
OPUC Data Request 71 – 1st Revised

OPUC Data Request 71

Please refer to PAC/200, Ralston/5. Regarding the statement "The negotiations for the new agreements were based upon a generation forecast that was part of the overall fueling budget for the Company":

(a) Please provide a narrative explanation of how the overall fueling budget is developed and its relationship to the annual TAM filing.

(b) Please provide a copy of the 2022 overall fueling budget or reference where it can be found in the TAM work papers.

1st Revised Response to OPUC Data Request 71

The attachment provided in response to subpart (b) of the Company's response dated May 7, 2021 was incomplete. The Company provides the following revised response to subpart (b):

(b) Please refer to Confidential Attachment OPUC 71-1 1st Revised, which provides the generation forecast that was used when negotiating and signing the new coal supply agreements. This includes PacifiCorp's overall fueling budget that was relied upon for those new agreements. This revised attachment replaces the original in its entirety.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

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

REDACTED
Docket No. UE 390
Exhibit PAC/602
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

1st Supplemental Response to OPUC Data Request 154

July 2021

UE 390 / PacifiCorp
June 28, 2021
OPUC Data Request 154 – 1st Supplemental

OPUC Data Request 154

Coal Supply Agreements
In Pac's response to Staff DR 72, the Company explained that the GRID model is used to inform negotiations on its coal contracts.

(a) Please provide work papers, model inputs, and model outputs for the GRID model run(s) that the Company used to inform its most recently signed Huntington coal contract.

(b) Please provide work papers, model inputs, and model outputs for the GRID model run(s) used to inform the Dave Johnston, Hunter, and Craig coal contracts introduced in this TAM filing.

Please provide the work papers, inputs, and outputs in electronic, Excel format with formulae and references intact.

1st Supplemental Response to OPUC Data Request 154

In further support of the Company's response to OPUC Data Request 154, dated June 2, 2021, the Company provides the following additional information regarding subpart (a):

PacifiCorp continues to object to this request as overly broad, outside the scope of this proceeding, cumulative, and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

(a) PacifiCorp does not have the requested Generation and Regulation Initiative Decision Tool (GRID) model run, however, the Company does have the output from the GRID model runs that supported the decision to enter into the Huntington coal contract. Please refer to Confidential Attachment OPUC 154 1st Supplemental, which provides the data which considered projected coal consumption for the remaining life of the plant. This information was included as part of Confidential Attachment Sierra Club 1.1 in docket UM 1712.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

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

REDACTED
Docket No. UE 390
Exhibit PAC/700
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Daniel J. MacNeil

July 2021

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Commercial Analytics Adviser.

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by the Company since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to the Company's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in the Company's jurisdictions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in California, Idaho, Oregon, Utah, Wyoming, and Federal Energy Regulatory Commission dockets.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the testimony of Staff witness Ms. Rose Anderson and Sierra Club witness Mr. Ed Burgess regarding the analysis of expected generation at Hunter before entering into the current coal supply agreements (CSAs).[1] In my testimony, I explain that there are two essential categories of alternatives to the Hunter CSAs: increased generation from new resources and increased generation from existing resources. I discuss how new generation and existing generation were analyzed when contracting for the Hunter coal supply. I also explain how this robust analysis supports the minimum take provisions in the Hunter CSA.

Q. Please summarize your rebuttal testimony.

A. Before entering new contracts for Hunter coal supply in 2020, the Company conducted robust analysis of the expected generation at Hunter over the term of the contract. The analysis supporting the Hunter CSAs directly identifies the potential for new and existing resources to impact Hunter coal demand. The analysis takes into account the interactions among units in the Company's coal and gas fleet, the Company's opportunities to purchase electricity in wholesale markets, and the impact of uncommitted renewable resource additions identified in the Company's 2019 Integrated Resource Plan (IRP) preferred portfolio. In addition to identifying Hunter coal demand under expected conditions, the Company also prepared high and low coal volume sensitivities by eliminating modeled market purchases and market sales, respectively. Eliminating market transactions is a reasonable proxy for a

[1] Staff/700, Anderson/11, 14, & 16; Sierra Club/100 Burgess/42–50.

variety of potential conditions that could impact coal demand, including changes to market prices, forecasted load, or new renewable resources, and the scale of this change is larger than the expected variation in these assumptions. As a result, it was prudent to set minimum take obligations for the Company's recent Hunter CSAs based on the low coal demand scenario.

III. HUNTER COAL SUPPLY AGREEMENTS

Q. Please describe Sierra Club's claims about the new Hunter CSAs.

A. Sierra Club contends that the Hunter CSAs' minimum take provisions are unreasonable because the Company's analysis did not account for a "general industry trend towards lower coal generation."[2]

Q. Does any other party share Sierra Club's concern?

A. No. Staff does express some general concerns about long-term CSAs and minimum take provisions[3] but believes that the [redacted] Hunter study appeared "robust" to inform the [redacted] CSAs.[4] The Oregon Citizens' Utility Board also reviewed the Hunter agreements and agrees that the minimum take provisions are reasonable for the 2022 Transition Adjustment Mechanism (TAM).[5]

Q. Did PacifiCorp consider Economic Cycling as suggested by Staff in its analysis for the Hunter CSAs?

A. Yes. Hunter Unit 1 and Hunter Unit 2 were allowed to cycle in the spring, consistent with assumptions previously used in Oregon TAM filings. While the Company did

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[2] Sierra Club/100, Burgess/45.
[3] Staff/700, Anderson/14–15.
[4] Staff/700, Anderson/16.
[5] CUB/100, Jenks/14.

not allow Hunter Unit 3 to cycle, having all three units off at once would be much more likely to result in reliability concerns.

Q. Is it appropriate to consider Economic Cycling when modeling and planning for a new CSA?

A. A robust analysis should capture the expected range of operating conditions and capabilities, but all modeling involves trade-offs between reality and achievable levels of detail. Over the past several years, the Company has been proactively increasing the flexibility of its coal fleet by the reducing minimum operating levels of its units. With a lower minimum operating level, the expense of keeping a unit online is reduced and it would require lower market prices or a longer duration for a shutdown to be economic. Because the minimum operating levels of the Company's combined cycle combustion turbines are significantly higher than most of its coal fleet, they have less ability to reduce output during the lowest price periods (typically the middle of the day). As a result, because many coal units have a greater ability to back down to make room for low-cost market purchases, it can be more cost-effective to cycle gas plants even though their variable operating costs are lower.

Balancing the flexibility of the Company's fleet and the need for flexibility as a result of uncertainty in load and variable resource output is complex for any model, and not all of the flexibility and uncertainty are currently represented within the Generation and Regulation Initiative Decision Tools (GRID). As a result, the appropriateness of "Economic Cycling" in an analysis involves consideration of more than just status of the "must run" setting in the GRID model. The Company's Hunter coal contract analysis has a reasonable balance of Economic Cycling for the Hunter units whose fuel requirements were being evaluated.

Q. Please describe the analysis the Company performed that supports its recent Hunter CSAs.

A. In June 2020, the Company used a version of its GRID model to assess Hunter coal volumes based on a range of possible coal prices and under low, expected, and high demand conditions. Because the GRID model includes only the Company's share of the Hunter units, the Company made an adjustment to account for coal consumed by the joint owners of Hunter 1 and Hunter 2. It also made adjustments to account for intra-hour dispatch and hour-to-hour ramping constraints that are not reflected in the GRID model.

Q. Is the GRID model used in the Hunter coal analysis the same as that used to prepare the Net Power Costs (NPC) filed by the Company in this proceeding?

A. Only in part. While the model itself is the same, the inputs and assumptions used in the Company's Hunter coal analysis incorporate a variety of inputs intended to reasonably reflect future conditions. For example, the GRID model used for the Hunter coal analysis includes committed resources (both owned and signed contracts), as well as uncommitted resources identified in the Company's 2019 IRP preferred portfolio.[6] Incorporating these additional inputs creates a more robust projection that accounts for [redacted] of annual coal consumption. In

[6] 2019 Integrated Resource Plan. Volume I, Chapter 8, Table 8.18: PacifiCorp's 2019 IRP Preferred Portfolio, *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

contrast, because the NPC in this proceeding focuses on known and measurable costs during the one-year test period, it does not include these additional resources.

Q. Please describe some of the key assumptions in the GRID model used for this analysis.

A. The GRID model used hourly electricity and monthly gas prices from the Company's March 2020 Official Forward Price Curve, along with the Company's June 2019 load forecast. The model also used normalized assumptions based on recent historical data for inputs such as heat rates, forced and planned outage rates, and so on that are generally consistent with what is used in the TAM.

Q. Did the Company's Hunter coal analysis account for the impact of potential future resource additions on coal demand?

A. Yes. The Hunter analysis included committed resources as of the time it was prepared in June 2020 as well as uncommitted resource additions based on its 2019 IRP preferred portfolio. The committed resources include 1,510 megawatts (MW) of new wind resources and 559 MW of new solar resources which at that time were expected to reach commercial operation in the fourth quarter of 2020, plus an additional 290 MW of solar resources with commercial operation dates extending into 2023. The uncommitted resources in the analysis included 69 MW of wind and 224 MW of solar combined with storage identified in the 2019 IRP preferred portfolio through 2023.

Q. Sierra Club argues that the Company should model forecasted generation from coal resources by equalizing the incremental/dispatch tier and the average/costing tier pricing.[7] Did the Company use this approach in analyzing the Hunter CSAs?

A. Yes. As outlined in the Company's Confidential Response to Commission Data Request 72, PacifiCorp used this approach to model expected coal consumption for the Hunter plant. The modeled incremental fuel costs for the Hunter plant were consistent with the full delivered contract cost (or "costing tier") for all volumes and no minimum take obligation was applied. As a result, the model results reflect the full range of costs contemplated in the Hunter CSAs, not just the incremental cost component.

Q. Did the Company incorporate optimization of contract requirements for other plants relative to coal volume constraints in its Hunter coal supply analysis?

A. Yes. The price of Hunter coal supply impacts the volumes from other sources, in particular Huntington and Jim Bridger, which are the largest coal plants with effective marginal costs comparable to those for Hunter, and thus the most likely to be impacted by changes in Hunter's dispatch. The Company's analysis ensured that Huntington and Jim Bridger volumes are consistent with their marginal costs in every scenario (i.e. the GRID volume output is on the supply curve for each unit). This required separate adjustments to incremental fuel price inputs in each year of each scenario.

[7] Sierra Club/100, Burgess/46.

Q. Sierra Club claims that the Company's modeling implemented "must run" settings as part of its Hunter analysis.[8] Is this true?

A. Yes; however, the intent of modeling is to produce a reasonable representation of reality and just because settings are available within a model doesn't mean that all possible input values are valid. As previously discussed, uncertainty and the resulting need for flexible resources are imperfectly represented within the GRID model. The Company's Hunter coal contract analysis has a reasonable balance of Economic Cycling for the Hunter units whose fuel requirements were being evaluated. Hunter Unit 1 and Hunter Unit 2 were allowed to cycle in the spring, consistent with assumptions previously used in Oregon TAM filings. While the Company did not allow Hunter Unit 3 to cycle, having all three units off at once would be much more likely to result in reliability concerns that GRID model is not capable of evaluating. In addition, because the minimum operating level of Hunter 3 is low, the impact of allowing it to cycle offline would not significantly change the annual volume. For example, operating Hunter Unit 3 at its minimum operating level for a week represents just [redacted] percent of the contracted coal minimum take. By comparison, the expected volume requirements were [redacted] percent higher than requirements in the low scenario that were used to inform the contracted minimum annual take requirements.

[8] Sierra Club/100, Burgess/47.

Q. Sierra Club claims that there is no indication that PacifiCorp has completed an analysis of potential alternatives to the Hunter CSAs.[9] Did the Company's analysis assess whether existing resource options were cost-effective alternatives to Hunter coal supply?

A. Yes. As discussed above, the Company's Hunter coal supply analysis used its GRID model, which optimizes market transactions and the dispatch of thermal resources. As a result, the Company analysis inherently assesses whether Hunter coal supply is cost-effective relative to the available alternatives, including market transactions, gas generation, and other coal generation.

Q. Sierra Club also claims that the Company did not compare the costs of a multi-year coal sales agreement to "other potential new generation sources other than market purchases."[10] Is this accurate?

A. No. As discussed above, the GRID runs used to forecast coal generation accounted for the resource portfolio identified in the 2019 IRP. So the Company did account for the potential impact of future resource alternatives in its analysis. To the extent that Sierra Club is arguing that the Company should have retired Hunter instead of entering new CSAs, the Company's 2019 IRP did not identify early retirement of Hunter as a component of the least-cost, least-risk preferred portfolio.

Q. Can PacifiCorp's existing natural gas generation replace the Hunter coal supply?

A. No. The Company has three combined cycle combustion turbines in Utah. Excluding duct firing capacity, with a high heat rate, these units total approximately

[9] Sierra Club/100, Burgess/47.
[10] Sierra Club/100, Burgess/47.

2,000 MW. By comparison, the Company's Utah load averages over 3,000 MW, and this doesn't account for load in Idaho, Wyoming, or the west side of the Company's system that may be economically served by Utah resources. As a result, the ability of PacifiCorp's gas-fired generation to replace the Hunter coal supply is limited, and the economic potential for gas-fired generation to replace the Hunter coal supply is accounted for in the Company's analysis.

Q. Can market purchases replace the Hunter coal supply?

A. No. The Company has limited transfer capability from major markets. Outside of the winter months, the Mid-Columbia market generally has the lowest prices of the markets to which the Company has access, especially in the spring when prices are usually depressed by hydro run-off. However, the Company has no transfer capability from the Mid-Columbia market to the east side of its system. While Mid-Columbia purchases can displace west-bound transfers from east-side resources to some extent, Mid-Columbia purchases cannot serve east-side loads. The transfer capability from east-side markets is also relatively small, and while there are benefits from displacing market purchases in some periods, the bulk of the Company's load must be served by internal resources. All of these interactions are accounted for in the Company's analysis.

Q. Is the Company required to maintain flexibility to balance its loads and resources?

A. Yes. The Company must continuously balance the loads and resources in its balancing authority areas from moment to moment to maintain reliable service for customers. The Company also must submit balanced load and resources as part of its participation in the energy imbalance market (EIM), and in addition must demonstrate that it has sufficient flexible capacity to cover expected changes as well as uncertainty across each upcoming hour. Forward and day-ahead market transactions do not allow for this intra-hour flexibility, and intra-hour flexibility via the EIM is only available once an entity has demonstrated it is capable of meeting its own requirements.

Q. Can uncertainty in future conditions impact coal supply requirements?

A. Absolutely. The Company's retail loads may be higher or lower than expected, wind, solar, and hydro generation will vary based on weather conditions, market prices for electricity and gas may go up or down and forced outages may take units offline.

Q. Did the Company assess how changes in demand would impact demand for Hunter coal generation?

A. Yes. An increase in load has the same net effect as a decrease in wind or solar generation due to weather conditions or a thermal unit outage. In light of this, rather than assessing the impact of each possible driver independently, the Company opted to use market transactions as a proxy for the range of possible conditions identified above. In the "High" Hunter demand scenario, market purchases were eliminated at the less liquid markets modeled in GRID: California-Oregon Border (COB), Mona, Mead, and Four Corners. Purchases at the relatively liquid Mid-Columbia and Palo Verde markets were not modified but continue to reflect restrictions associated with transmission limits. Supply which would otherwise have been met via market purchases then must be met with alternative resources. This is comparable to continuing to make market purchases and being faced with an increase in load or a decrease in the availability of other generation. Demand for Hunter generation is only increased under this scenario in intervals where it is among the most economic options that was not fully utilized. In the "Low" Hunter demand scenario, market sales were eliminated at the less liquid markets modeled in GRID: COB, Mona, Mead, and Four Corners. This results in reduced Hunter generation in intervals where it would otherwise have been among the most expensive options dispatched to support economic wholesale sales.

Q. How much were market sales impacted in the "Low" scenario, relative to the expected level?

A. Over the study period, an average of 370 MW of market sales were eliminated in the "Low" scenario.

Q. How does the change in market sales compare to other possible changes in the Company's load and resource balance?

A. The Company's load forecast for 2021 has been impacted by economic changes related to the COVID-19 pandemic, but this change only amounts to an average reduction of 130 MW, or just 35 percent of the "Low" scenario market sales change. At a 30-35 percent capacity factor, which is comparable to the expected output of wind or solar resources in Utah, more than 1,000 MW of new renewable resources would be necessary to be equivalent to the "Low" market sales.

Q. Have actual resource acquisitions kept pace with the uncommitted resources identified in the 2019 IRP and included in the Hunter coal supply analysis?

A. No. The 2019 IRP preferred portfolio included new "customer preference" renewable resources with a cumulative capacity totaling 159 MW in 2021, 223 MW in 2022, and 296 MW in 2023. Since the Hunter coal supply analysis was prepared in June 2020, the Company has only entered a single 20 MW contract that will impact 2021, and that has a commercial operation date on December 31, 2021. New resource capacity in 2022 and 2023 is also delayed relative to the uncommitted resources from the 2019 IRP preferred portfolio that were included in the Hunter coal supply analysis. This reduction in resources would tend to increase demand for Hunter's generation, and demonstrates that the Company's analysis was conservative.

Q. Is the performance of the Hunter plant within the TAM filing relevant to the prudence of the Company's actions in entering multi-year contracts for Hunter coal supply during 2020?

A. No. The Company's decision to enter multi-year contracts for Hunter coal supply during 2020 was based on the Hunter coal analysis described herein, and not on the contents of the TAM forecast. As Sierra Club notes, a "long-run marginal cost perspective is necessary when considering new fuel supply agreements that can last several years."[11] As demonstrated above, the Company rigorously analyzed the Hunter CSAs and their associated minimum take obligations within this long-term framework.

Q. Sierra Club also recommends that PacifiCorp should be responsible for any shortfall payments below the minimum take provisions.[12] Is this discussion relevant to the TAM proceeding?

A. No. First, PacifiCorp was not imprudent for executing the Hunter CSAs and therefore should not bear reasonably incurred costs if generation falls below the minimum take level in the agreements. Based on the contemporaneous analysis

[11] Sierra Club/100, Burgess/29.
[12] Sierra Club/100, Burgess/46.

described above, the minimum take levels in the Hunter CSAs are reasonable.

Second, as Sierra Club notes, "PacifiCorp may already have some exposure to the cost of shortfall payments due to the PCAM construct and related deadbands."[13] The Company believes that its coal forecasts reflect operational realities, that Hunter will not fall below the contracted minimum take levels absent extreme changes in conditions, and that contracting for greater flexibility in the Hunter coal contracts would have resulted in an expectation of higher overall costs for customers. In any event, a discussion of the true up costs between expected costs and operational costs should occur during the power cost adjustment mechanism proceeding and not the TAM.

Q. Does this conclude your reply testimony?

A. Yes.

[13] Sierra Club/100, Burgess/46.

REDACTED
Docket No. UE 390
Exhibit PAC/800
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Mary M. Wiencke

July 2021

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Mary M. Wiencke. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. I am employed by PacifiCorp as Vice President of Market, Regulation, and Transmission Policy.

Q. Please describe your education and business experience.

A. I have a Bachelor of Arts degree in Environmental Science from Barnard College and a J.D. from Lewis & Clark Law School. I have been employed by PacifiCorp for 13 years in various positions of responsibility in both legal and policy roles.

Q. Please explain your responsibilities as PacifiCorp's Vice President of Market, Regulation, and Transmission Policy.

A. My current responsibilities include developing PacifiCorp's environmental policy, strategy, and programs as well as ensuring compliance for company-wide renewable portfolio standards (RPS) and reporting of greenhouse gas (GHG) emissions for California, Oregon, and Washington. Most relevant to this proceeding, I manage PacifiCorp's compliance with the California Air Resources Board (CARB) Mandatory Reporting Regulation and Cap and Trade Program.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the Purpose of your reply testimony?

A. The Purpose of my testimony is to respond to certain concerns regarding how PacifiCorp complies with its GHG Compliance obligations in California raised by Staff. Testimony regarding PacifiCorp's forecasting of the GHG elements in the transition adjustment mechanism (TAM) is included in the testimony of Mr. Douglas R. Staples. Additionally, I address Calpine's recommendation regarding transfer of Renewable Energy Certificates (RECs) to Electricity Service Suppliers (ESSs) for Direct Access Customers.

III. PACIFICORP'S CALIFORNIA GHG OBLIGATION

Q. What concerns does Staff raise regarding PacifiCorp's GHG Compliance?

A. Staff's testimony raises a number of concerns regarding PacifiCorp's assumed compliance costs with the GHG requirements from the CARB. First, Staff is concerned that the Company does not reflect the lower compliance costs associated with California Carbon Offsets (CCO) in its CARB Compliance cost.[1] Second, Staff raises the question of whether PacifiCorp should be using RECs to reduce its CARB compliance requirement.[2] Finally Staff raises some concerns regarding the information provided by PacifiCorp.[3]

Q. Can you please provide an overview of PacifiCorp's California GHG Compliance Requirements?

A. PacifiCorp's GHG obligation under California's Mandatory Reporting Rule (MRR) and Cap and Trade program is unique due to PacifiCorp's status as a multi-jurisdictional retail provider.[4] PacifiCorp has separate GHG obligations in California for its California retail sales and for its wholesale exports to California such as those exported to California through the Energy Imbalance Market (EIM).

[1] Staff/100, Enright/27.
[2] Staff/100, Enright/27.
[3] Staff/100, Enright/30.
[4] *See* Cal. Code. Regs. tit. 17 § 95111.

Q. Does PacifiCorp's obligation for its California retail sales have any impact on customer retail rates in Oregon?

A. No. The GHG costs and revenues associated with PacifiCorp's retail obligations are fully covered by California customers and are not reflected in Oregon rates.

Q. Please explain PacifiCorp's obligation with regard to wholesale exports (like EIM).

A. PacifiCorp's GHG obligation associated with wholesale exports to California, such as those exported through the EIM, are covered by wholesale transaction cost adders. These flow through to Oregon customer rates and are an expense associated with making sales into California, although offset by EIM benefits. PacifiCorp tracks its wholesale obligation as transactions occur and purchases allowances consistent with its risk management policy to cover the obligation at the best available price.

Q. Staff contends that CCOs are lower cost compliance instruments when compared to California Carbon Allowances (CCAs) and [redacted].[5] Do you agree?

A. No, CCAs provide a more reliable compliance mechanism than CCOs. [redacted]

[5] Staff/100, Enright/28.

[redacted]

Q. Staff further states that PacifiCorp could leverage REC generation from outside of California to reduce its California Cap-and-Trade compliance requirement.[6] Is this accurate?

A. No, PacifiCorp cannot use REC generation to reduce its compliance requirement. The RPS adjustment is the only provision under Cap-and-Trade that involves an entity reducing its compliance obligation through the retirement of a REC.[7] The RPS adjustment is only available to California load-serving entities who are subject to the California RPS. It is not available for wholesale importers. Therefore, the RPS adjustment would only potentially be available to meet PacifiCorp's retail GHG obligation and not the obligation regarding wholesale imports. As discussed above, PacifiCorp's retail GHG obligation is not a part of Oregon rates and is not reflected in the TAM. Additionally, PacifiCorp is not eligible for the RPS adjustment even for its retail obligation, because 100 percent of PacifiCorp's RPS eligible resources are already captured in its calculation of emissions.

Q. Staff raises concerns that PacifiCorp has not provided details about precisely what instruments it uses to meet its CARB compliance requirements despite "multiple rounds of discovery and engagement[.]"[8] How do you respond?

A. PacifiCorp remains committed to working through the discovery process and trying to provide the information requested by Staff. However, PacifiCorp is constrained

[6] Staff/100, Enright/29-30.
[7] Cal. Code. Regs. tit. 17 §95852(b)(4).
[8] Staff/100, Enright/30.

directly by the California Cap-and-Trade regulation which limits information sharing related to the following topics:[9]

- Intent to participate, or not participate, at auction, and auction approval status;
- Bidding strategy at any auctions, including the specification of an auction settlement price or range of potential auction settlement prices at which an entity is willing to buy or sell allowances;
- Bid price or bid quantity information at past or future auctions; and
- Information on the amount of any bid guarantee provided to the financial services administrator

PacifiCorp reached out and received guidance from CARB regarding the scope of the information that could be provided to Staff, and worked diligently to provide as much information and detail as possible within the constraints placed by CARB. Further, PacifiCorp communicated these constraints to Staff and sought to work with them to try and provide the information that was requested. PacifiCorp has provided Staff with informative materials such as its annual MRR GHG reports going back to 2014, which provide all GHG obligation calculations for both retail and wholesale categories since that time. This reporting, coupled with the risk policy and narrative descriptions provided via data responses should provide the additional detail that Staff is requesting.

Q. Staff has specifically requested the "standardized CARB one – Reporting workbook for EPE Importers and Exporters".[10] Has this been provided?

A. Yes, PacifiCorp provided this information for years 2014 through 2019 in OPUC Data Request 124, which was served to Staff on May 26, 2021.

[9] Cal. Code. Regs. tit. 17 §95914(c)(1).
[10] Staff/100, Enright/31.

IV. RESPONSE TO CALPINE'S RECOMMENDATION ON REC TRANSFERS

Q. Calpine raises concerns regarding the transfer of RECs to a direct access customer ESS for compliance with Oregon's RPS.[11] Has this concern been resolved?

A. Yes, House Bill 2021 modified the definition of a bundled RECs to allow an ESS to use transferred RECs to meet their RPS requirement when those RECs have been transferred from an electric company and meets certain other requirements. This legislation has been passed by the Oregon state legislature and is awaiting the Governor's signature.

Q. Does this conclude your direct testimony?

A. Yes.

[11] Calpine/100, Higgins/23-24.

Docket No. UE 390
Exhibit PAC/900
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

July 2021

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Robert M. Meredith and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Director, Pricing/Cost of Service.

Q. Briefly describe your educational and professional background.

A. I graduated from Oregon State University with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 16 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 11 years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in Oregon, Utah, Wyoming, Washington, Idaho, and California.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I respond to the testimony of Calpine Energy Solutions, LLC (Calpine) regarding the Consumer Opt-Out Charge and the testimony of Small Business Utility Advocates (SBUA).

III. RESPONSE TO CALPINE TESTIMONY

Q. Please explain the purpose of the Consumer Opt-Out Charge for participants in the Company's five-year direct access opt-out program.

A. The Consumer Opt-Out Charge is intended to prevent cost shifting that can occur when a direct access participant permanently departs from the Company's system leaving behind stranded fixed generation costs. The Company must plan for and procure fixed generation resources, so that it can reliably serve its customers' load. Non-participating customers are protected by the Consumer Opt-Out Charge, because it collects from departing participants the fixed generation costs for years six through 10 and is offset by the value of the freed-up power made available.

Q. How does the Consumer Opt-Out Charge minimize cost shifting?

A. The Consumer Opt-Out Charge minimizes cost shifting to nonparticipating customers when customers in this program cease paying Base Supply Service in Schedule 200 after five years. In essence, departing customers are charged a five-year levelized payment to cover the fixed generation costs they would otherwise have paid for from years six through ten. This provides some protection to non-participating customers, because it offsets the stranded fixed generation costs that the permanent direct access participant has abandoned.

Q. Please explain how the Consumer Opt-Out Charge works.

A. Before each direct access election window, the Company will post on its website the Consumer Opt-Out Charge related to generation costs. The Consumer Opt-Out Charge may be subject to change, as authorized by the Commission, to reflect changes in Schedule 200 approved subsequent to the direct access election window.

The Consumer Opt-Out Charge approved for the cohort of customers electing service during each direct access enrollment period will apply during the five-year transition period for that cohort of customers. After five years of continuous participation, customers on Schedule 296 will no longer be subject to the Consumer Opt-Out Charge or to charges in Schedule 200, Base Supply Service, and they will not receive or pay Transition Adjustments.

Q. How is the Consumer Opt-Out Charge calculated?

A. The Consumer Opt-Out Charge is a valuation of the fixed generation costs incurred by the Company to serve customers, offset by the value of the freed-up power made available by the departing customers for years six through ten. First, Transition Adjustments are projected for years six through ten. Next, the current Base Supply Service rates are also projected for years six through 10. The Consumer Opt-Out Charge is then calculated by combining the net present value of the projected Transition Adjustments and Base Supply Service rates for years six through 10 and converting the result to a five-year nominal levelized payment stream using the Company's discount rate.[1]

Q. What is Calpine's concern regarding the Consumer Opt-Out Charge?

A. Calpine has raised a concern that the Consumer Opt-Out charge should be a negative value and that PacifiCorp has constrained the calculation such that the Consumer Opt-Out charge can never be below zero.[2]

[1] The Company's after-tax weighted average cost of capital.
[2] Calpine Solutions/100, Higgins/16.

Q. Has the Consumer Opt-Out Charge ever been zero in the past?

A. No. This outcome is unique and it may not be persistent as the transition adjustment mechanism (TAM) is updated throughout the year.

Q. Do you agree with Calpine's concern?

A. No. The Consumer Opt-Out Charge was labeled a charge for a reason. Setting this charge as a negative number and effectively converting it to a credit would fundamentally be at odds with its purpose. The Consumer Opt-out Charge was designed to recover some of the stranded costs of the fixed generation system that a departing participant would no longer pay for once its five year transition is completed. To the extent that the forecast value of freed-up generation offsets those fixed generation costs, then there is no charge. That is what the values are indicating in this year in the Company's sample calculation.

Q. How would a negative Consumer Opt-Out Charge contribute to cost-shifting?

A. If the Consumer Opt-Out Charge was a negative value, it would operate as a credit against the transition adjustment in years one through five. Functionally, this means that five-year direct access customers that choose to opt-out will be reducing their contribution to net power costs in years one through five (or increasing their benefits) through a credit that would be calculated based on the potential forecast net benefit of them leaving the system in years six through 10. By reducing their contribution to net power costs in years one through five, non-direct access customers will bear the burden of this credit. The Consumer Opt-Out Charge would then not function as intended as a check against shifting stranded costs, but would rather be an inappropriate bonus transition payment for potential benefits out in years six through

10. Setting the Consumer Opt-Out Charge at a floor of zero is good policy and is consistent with Oregon law, which states that "the provision of direct access to some retail electricity consumers must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company."[3]

Q. Calpine contends that Oregon regulations (and PacifiCorp's past testimony) require that direct access customers must pay or receive 100 percent of transition costs or benefits and that PacifiCorp's calculation of the Consumer Opt-Out Charge violates this principle.[4] Do you agree?

A. No. Schedule 296 contains two distinct components with different prices—Transition Adjustments and a Consumer Opt-Out Charge. Setting the Consumer Opt-Out Charge at zero does not impair the value of Transition Adjustments that a permanent opt-out participant would pay or be credited for in its five year transition period. Since the Consumer Opt-out Charge is a charge that is intended to recover the fixed costs of generation, setting it to zero does not deprive Direct Access customers of the net value "of all economic utility investments and all uneconomic utility investments of the electric company…"[5] Direct Access customers are simply not paying for the fixed costs of generation when it is fully offset by the value of freed up energy in years six through 10. In fact, Calpine's suggestion that the Consumer Opt-Out Charge should be a credit could in fact result in Direct Access customer not fully paying for utility investments in years one through five.

[3] ORS 757.607(1).
[4] Calpine Solutions/100, Higgins/18.
[5] OAR 860-038-01600 (1).

Q. What is your recommendation?

A. I recommend that the Commission protect non-participating customers and reject Calpine's recommendation to allow the Consumer Opt-Out Charge to become a Consumer Opt-Out Credit.

IV. RESPONSE TO THE TESTIMONY OF SBUA

Q. What is your overall impression of SBUA witness Mr. Wertz' testimony in this proceeding?

A. SBUA's testimony is generally confusing and seems to misunderstand the scope of the TAM proceeding.

Q. Is PacifiCorp the only party with concerns about the content of SBUA's testimony?

A. No. The Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens Utility Board (CUB) filed a petition to deny TAM case certification to SBUA based on the content of their testimony.[6]

Q. Please attempt to describe SBUA witness Mr. Wertz' testimony regarding the TAM forecast and proposed rates for small general service Schedule 23 in this TAM?

A. SBUA witness Wertz refers to Exhibit PAC/303, Ridenour/1 to show that Schedule 23 TAM rates are based solely on energy usage and do not include a demand charge. Mr. Wertz then states that load characteristics are to be obtained from Advanced Metering Infrastructure (AMI) data. Mr. Wertz claims that this data is necessary in

[6] *See* AWEC and CUB Response to SBUA Petition for Case Certification (June 28, 2021).

light of the recent economic downturn in order to determine a just and reasonable outcome for Schedule 23 customers.

Q. How do you respond?

A. AMI data is not necessary to set just and reasonable rates in the Company's TAM. Schedule 201 primarily recovers the Company's net power costs. Schedule 201 prices for all rate schedules are energy-only rates, as has been the case since the TAM was first implemented. Energy rates are an appropriate basis for recovering the power costs set in the TAM. Granular AMI data is unnecessary to determine overall energy consumption by class.

TAM rates are set based on the energy forecast for the forward-looking TAM rate effective period. In accordance with the TAM Guidelines adopted in Order No. 09-274,[7] the test period for the TAM is the year during which the Schedule 201 rates will be effective, which in this proceeding is the forecast period of the 12 months ending December 31, 2022. An updated forecast is used each year in setting TAM rates.

It is unclear how Mr. Wertz is recommending to incorporate changes based on AMI data. Billing demand data is available without AMI data but is not used to set TAM rates. The historical test period billing determinants used to shape the forecast billing determinants were updated recently in docket UE 374, the Company's most recent general rate case.[8] The TAM is a narrowly focused filing which does not warrant a complex update to the historical test period. Such an update would provide

[7] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service,* Docket No. UE 199, Order No. 09-274 (July 16, 2009).
[8] *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision,* Docket No. UE 374, PAC/1400, Meredith/17-18 (Feb. 14, 2020).

no additional accuracy in setting energy-based TAM rates, especially given that the forecast load is updated in the TAM. Using an updated load forecast appropriately reflects expected load for all rate schedules for the period that the rates will be in effect, resulting in just and reasonable rates for all customers.

Q. Would demand-based rates in the TAM be beneficial for businesses struggling during the pandemic as Mr. Wertz seems to suggest?

A. Not necessarily. Mr. Wertz's testimony is particularly concerned with the recent economic downturn's effect on small business customers who have been forced to close or reduce energy usage. Considering such a business customer, transferring cost recovery from energy charges into demand charges would likely increase such a customer's electricity bills. For example, a small store that was previously open seven days a week but reduced its hours to being open two days a week would see reduced kilowatt-hour energy usage but not a reduced maximum monthly kilowatt demand usage. Therefore, the customer might lower the amount it pays for energy-based charges but would potentially not lower the amount it pays for demand-based charges. SBUA's argument here does not make sense.

Q. SBUA witness Mr. Wertz indicates that there is a reason to consider Schedule 23 in this TAM with relation to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). Could you please provide a brief description of the 2020 Protocol?

A. The 2020 Protocol was approved by the Commission in docket UM 1050 on January 23, 2020, to be used as the inter-jurisdictional allocation methodology to allocate costs and benefits across the Company's six state jurisdictions.[9] The Company filed its most recent general rate case in Oregon using this allocation methodology. The final order approving rates set using this methodology was issued on December 18, 2020.

Q. To be clear, does the 2020 Protocol have any bearing on how costs are allocated amongst the rate schedules in Oregon?

A. No. The 2020 Protocol is used to allocate costs amongst the states PacifiCorp serves, not to allocate costs amongst customers within the state.

Q. Please describe SBUA's testimony regarding the 2020 Protocol.

A. SBUA witness Mr. Wertz states that he has not reviewed the Load Based Dynamic Allocation Factors used in this TAM, but claims that allocation factors used by the Company are based on historical actuals which do not account for recent economic conditions for Schedule 23 customers.

Q. Is SBUA's argument relevant for this proceeding?

A. No. The 2020 Protocol allocation factors used in this TAM are calculated based on forecasted capacity and energy data. The forecast period used for this TAM is the calendar year 2022. Using a 2022 forecast appropriately reflects conditions expected for the period these TAM rates will be in effect.

[9] *See In the Matter of PacifiCorp d/b/a Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol,* Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).

Q. What does SBUA suggest related to Energy Imbalance Market (EIM) benefits related to Schedule 23?

A. SBUA witness Mr. Wertz suggests that Schedule 23 TAM rates should reflect a discount based on an assumed increase in sales through the EIM of energy from decreased usage by Schedule 23 customers due to economic conditions.

Q. How do you respond to this suggestion?

A. Again, Mr. Wertz's position here does not make sense and his recommendation lacks specificity and support. EIM benefits flow through the TAM in net power costs and are allocated amongst the rate schedules based on a generation rate spread. Costs from the TAM are projected for conditions that are expected to occur in the future. They are not a back-cast of conditions experienced in the past. As such, attributing some potential benefit from the past is inappropriate in this proceeding.

It is also important to note that EIM prices may fluctuate significantly during different times in a year or at different nodes within the WECC. At times these prices can even be negative indicating that at the margin, reduced load can actually be more costly to serve. Absent further evidence from SBUA, there is no way to know whether reductions in small business load resulted in EIM benefits and even if it did provide such support, a special imputation of such a benefit would not be consistent with the allocation of forecast costs and benefits in the TAM.

Q. Does this conclude your reply testimony?

A. Yes.