

June 9, 2020

VIA ELECTRONIC FILING

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

Re: UE 356—PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of David G. Webb, Seth Schwartz, Dana M. Ralston, Doug Young, and Ramon J. Mitchell.

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. 20-145.

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

Sincerely,



Michael Wilding
Director, Net Power Costs & Regulatory Policy

Enclosures

CERTIFICATE OF SERVICE

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

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Dated this 9th day of June, 2020.



Mary Penfield
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REDACTED

Docket No. UE 375

Exhibit PAC/500

Witness: David G. Webb

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

REDACTED

Reply Testimony of David G. Webb

June 2020

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ATTACHED EXHIBITS

Exhibit PAC 501 - 2021 TAM Oregon-Allocated Net Power Costs Reply Filing

Exhibit PAC 502 - 2021 Results of Updated Net Power Cost Study Reply Filing

Exhibit PAC 503 - 2021 Updates Summary Reply Filing

1 **Q. Are you the same David G. Webb who previously submitted direct testimony in**
2 **this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the**
3 **Company)?**

4 A. Yes.

5 **I. PURPOSE AND SUMMARY OF TESTIMONY**

6 **Q. What is the purpose of your reply testimony?**

7 A. My testimony has two sections. First, I provide a Transition Adjustment Mechanism
8 (TAM) update (Reply Update), as allowed under TAM Guidelines adopted by the
9 Public Utility Commission of Oregon (Commission) in Order No. 09-274 and revised
10 in Order Nos. 09-432 and 10-363.¹ In the Reply Update, I explain the reasonableness
11 of the Company's updated Oregon net power costs (NPC) of \$358.4 million for the
12 test period of the 12 months ending December 31, 2021.² This results in a rate
13 decrease of \$47.4 million compared to the 2020 TAM. I provide corrections and
14 contract, fuel, and forward price curve updates to the Company's February 14, 2020,
15 filing (Initial Filing).

16 Second, my reply testimony responds to various issues and adjustments raised
17 in the opening testimony of Commission Staff (Staff) witnesses Mr. Scott Gibbens,
18 Ms. Moya Enright, Ms. Sabrina Soldavini, and Ms. Kathy Zarate; Alliance of
19 Western Energy Consumers (AWEC) witness Mr. Bradley G. Mullins; Oregon

¹ *In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 10 (July 16, 2009); *In the Matter of PacifiCorp's 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 (Oct. 30, 2009); *In the Matter of PacifiCorp's 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 (Sept. 16, 2010).

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

1 Citizens' Utility Board (CUB) witness Mr. Bob Jenks; and Sierra Club witness
2 Mr. Ed Burgess.

3 **Q. Please identify the other witnesses providing reply testimony supporting the**
4 **2021 TAM.**

5 A. Four other witnesses are providing reply testimony in support of the Company's 2021
6 TAM filing. Mr. Seth Schwartz, President, Energy Ventures Analysis, Inc., provides
7 expert, third-party testimony in support of the prudence of the Company's coal
8 supply agreements and their consistency with industry standards, and confirms that
9 the Company's use of incremental costs for dispatch of coal plants reflects industry
10 practice and is beneficial to customers. Mr. Dana M. Ralston testifies in support of
11 the Company's updated coal costs and responds to the testimony of Sierra Club
12 witness Mr. Burgess, CUB witness Mr. Jenks, and AWEC witness Mr. Mullins. In
13 response to issues raised by Staff witness Ms. Enright and Sierra Club witness
14 Mr. Burgess, Mr. Doug Young provides testimony on how PacifiCorp prepares
15 generation forecasts for its business planning and fuel contracting processes.
16 Mr. Ramon J. Mitchell testifies in support of the Company's updated calculation of
17 total Energy Imbalance Market (EIM) benefits and responds to adjustments proposed
18 by Staff witness Ms. Enright, CUB witness Mr. Jenks, and Sierra Club witness
19 Mr. Burgess.

20 **Q. Please summarize your reply testimony.**

21 A. I demonstrate the reasonableness of PacifiCorp's NPC in the 2021 TAM, which
22 represents a rate decrease of \$47.4 million, through the following points:

- 23
- Consistent with Commission precedent, the goal of the TAM as filed is to model

1 PacifiCorp's actual NPC as accurately as possible. The adjustments filed by
2 parties would decrease the accuracy of NPC and fail this threshold test.

- 3 • With few exceptions, the parties' adjustments do not challenge prudence and
4 instead focus on technical modeling issues. The parties' adjustments need to be
5 viewed in the context of PacifiCorp's chronic under-recovery of its prudent NPC
6 in Oregon. In 2019, the Company experienced the largest under-recovery yet in
7 the TAM, almost \$42 million. It is unreasonable to respond to this problem by
8 adopting new modeling adjustments in this case that widen the gap between actual
9 NPC and NPC in the TAM.
- 10 • Staff's recommendations and adjustments related to economic cycling are
11 unjustified because the Company's current approach more than captures the
12 economic cycling available in actual operations. The Company has significantly
13 reduced minimum operating levels of its coal units, which is a better way to
14 optimize coal plant operations than cycling plants on and off. This approach
15 results in reduced NPC, higher EIM benefits, and greater reliability.
- 16 • Sierra Club's adjustments and recommendations related to PacifiCorp's coal costs
17 generally rely on the false premise that the Company should dispatch coal
18 generation (unlike all other generation) using average instead of incremental
19 costs. This approach would increase NPC. In addition, Sierra Club's arguments
20 that coal generation could be replaced with other generation in 2021 are simplistic
21 and inaccurate, and removing certain coal plants from NPC and replacing them
22 with available generation in GRID would significantly increase costs and decrease
23 reliability. Sierra Club's argument entirely disallowing certain third-party fuel

1 costs on the basis that they are “fixed costs” is contrary to the TAM Guidelines
2 and Commission precedent. Sierra Club’s recommendations for future review of
3 coal contracts are unnecessary given the robust review process already available
4 in the TAM.

- 5 • AWEC’s adjustment related the Day-Ahead and Real-Time system balancing
6 transactions (DA/RT) adjustment is unjustified and directly contrary to past
7 positions AWEC has advocated.
- 8 • With respect to other adjustments proposed by the parties, PacifiCorp is
9 accepting: (1) Staff’s proposal to update the load forecast for the TAM when and
10 if the load forecast is updated in the Company’s pending general rate case, docket
11 UE 374; (2) CUB’s proposal to withdraw Deer Creek legacy pension costs from
12 the TAM so that they may be added to base rates in docket UE 374; (3) AWEC’s
13 adjustment to reduce the load in eastern Wyoming to account for the line loss
14 benefits resulting from the construction of the Aeolus-to-Bridger/Anticline
15 transmission line; and (4) Staff’s proposal to update NPC when the 2019 flexible
16 reserve study is updated in the Integrated Resource Plan (IRP). PacifiCorp
17 explains why all other adjustments proposed by the parties are unreasonable and
18 contrary to the goal of increasing the accuracy of NPC in the TAM. This includes
19 Staff’s Qualifying Facilities (QF) and nodal pricing model adjustments; CUB’s
20 transmission wheeling revenues adjustment; AWEC’s adjustments on natural gas
21 optimization, adding a 300 megawatt (MW) transmission link from Jim Bridger to
22 Walla Walla, and quantifying a reliability benefit from the construction of the
23 Aeolus-to-Bridger/Anticline transmission line; and Staff’s and CUB’s adjustment

related to installation of selective catalytic conversion (SCR) equipment at Jim Bridger Units 3 and 4.

- There is no basis for adopting AWEC's proposal to change the direct access opt-out charge in the TAM at this time, especially given the Commission's pending investigation into direct access policy issues in docket UM 2024.

II. REPLY UPDATE

Q. How has your NPC recommendation changed from the initial filing?

A. On a total-company basis, NPC increased by \$5 million, from \$1.401 billion to \$1.406 billion. On an Oregon-allocated basis, NPC increased from \$356.6 million to \$358.4 million, a \$1.8 million increase from the initial filing.

Exhibit PAC/501 shows that PacifiCorp's Reply Update proposes a rate decrease of \$47.4 million, approximately 3.6 percent average rate decrease. The results of the Company's updated NPC study are provided in Exhibit PAC/502. A list of all adjustments and updates made, along with the approximate impact of each on NPC, is provided in Exhibit PAC/503.

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 the most recent actual EIM benefit information as well as the updated OFPC.

Additionally, PacifiCorp made two changes to NPC in response to parties'

1 testimony. First, as proposed by AWEC, the Company reduced the load in eastern
2 Wyoming by 11.6 MW to account for the line loss benefits resulting from the
3 construction of the Aeolus-to-Bridger/Anticline transmission line. Second, as
4 proposed by CUB, the Company reduced fuel costs by removing Deer Creek mine
5 legacy pension costs from the TAM, so they can be added to base rates in the
6 Company's concurrent general rate case.

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

8 A. Figure 1 illustrates the change in the total-company forecast NPC by category
9 compared to the NPC in the initial filing.

10

FIGURE 1
Net Power Cost Reconciliation

	(\$ millions)	\$/MWh
OR TAM 2021	\$1,401	\$23.14
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	28	
Purchased Power Expense	17	
Coal Fuel Expense	(37)	
Natural Gas Fuel Expense	(2)	
Wheeling and Other Expense	(0)	
Total Increase/(Decrease) to NPC	5	
OR TAM 2021 Reply	<u>\$1,406</u>	\$23.27

11 The changes in the components of NPC from the initial filing are largely
12 driven by lower forward market prices for electricity. Lower wholesales revenue and
13 higher purchase power expense resulted in higher NPC. This increase is partially
14 offset by lower coal and gas fuel expense. Wheeling and other expense remained flat.

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

2 A. The Reply Update includes the following updates (the NPC impacts are based on the
3 initial filing):

4 • **OFPC and Short-Term Firm Transactions** – The Company updated the OFPC
5 from December 31, 2019 to March 31, 2020. On average, market prices for
6 electricity at the Mid-Columbia and Four Corners markets decreased by
7 approximately eight percent. Market prices for natural gas increased, on average,
8 by approximately one percent. Short-term sales and purchase transactions for
9 electricity and natural gas were also updated through April 1, 2020. These
10 updates increased Oregon-allocated NPC by approximately \$3.8 million.

11 • **EIM Inter-Regional Transfer Benefits and Greenhouse Gas (GHG)**
12 **Benefits** – PacifiCorp's estimated EIM benefits for 2021 have been updated to
13 include the most recent information through April 2020. On a total-company
14 basis, the expected inter-regional transfer benefits are [REDACTED], a decrease of
15 [REDACTED]; the forecast GHG benefits are [REDACTED], a decrease of
16 [REDACTED]. This update increased Oregon allocated NPC by approximately
17 [REDACTED].

18 • **Long-Term Contracts** – The Company has included two long-term contract
19 updates, which resulted in a \$625,000 increase to Oregon-allocated NPC.

20 ○ **Cove Mountain Solar II** – The Cove Mountain Solar II contract expense was
21 updated to an annual true-up schedule from a monthly true-up schedule. The
22 delivered energy was updated by using the calendar year 2021 forecast,
23 instead of the calendar year 2020 forecast.

○ **Sigurd Solar Commercial Operational Date (COD)** – The COD of Sigurd Solar, an 80 MW solar plant in Sevier County, Utah has been postponed to June 30, 2021, due to the recent disruption of the global supply chain. The Contract Delay Rate (CDR) was applied to the updated COD.

- **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 decreases NPC by approximately \$6.6 million on an Oregon-allocated basis.
- **Gas Pipeline Expense** – Transportation costs to supply natural gas to the Gadsby, Hermiston and Naughton 3 plants are updated to reflect new natural gas supply and transportation rates for these plants. The update increases NPC by approximately \$213,000 on an Oregon-allocated basis.

III. REPLY TESTIMONY

A. Purpose of the TAM

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.³ Significantly, the TAM also sets PacifiCorp's Oregon-allocated NPC for the upcoming year.⁴ The direct access transition adjustments are calculated by comparing the value of energy used to serve direct access loads with the cost of service rate under the customers' specific energy-only tariff. The Commission

³ *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).

⁴ *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).

1 adopted an annual NPC update to ensure that both the value of freed-up energy and
2 the cost of service rate are calculated for the same period using the same data. The
3 Commission has articulated the importance of accurate NPC modeling in the TAM:

4 PacifiCorp's TAM is an annual filing in which PacifiCorp projects
5 the amount of [NPC] to be reflected in customer rates for the
6 following year, as well as to set transition charges for customers
7 electing to move to direct access. The TAM effectively removes
8 regulatory lag for the Company because the forecasts are used to
9 adjust rates. For that reason, the accuracy of the forecasts is of
10 significant importance to setting fair just and reasonable rates. Our
11 goal, therefore, is to achieve an accurate forecast of PacifiCorp's
12 [NPC] for the upcoming year.⁵

13 **Q. Please briefly describe PacifiCorp's Power Cost Adjustment Mechanism**
14 **(PCAM) authorized by the Commission.**

15 A. Commission Order No. 12-493 approved a PCAM to allow PacifiCorp to recover the
16 difference between actual PCAM costs incurred to serve customers and the base
17 PCAM costs established in PacifiCorp's annual TAM filing.⁶ PCAM costs include
18 NPC, other revenues, and federal production tax credits (PTC). As the Commission
19 observed when it adopted a PCAM for Portland General Electric Company (PGE),
20 the PCAM has been designed so that the utility "will bear normal business risk
21 associated with actual power costs varying from forecast."⁷

22 **Q. Please describe the relationship of the TAM and PCAM.**

23 A. Each year the PCAM compares the NPC collected from Oregon customers in rates set
24 in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is

⁵ *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).

⁶ *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).

⁷ Order No. 07-015 at 17-19.

1 subject to an asymmetrical deadband between a \$30 million under-collection and a
2 \$15 million over-collection, a symmetrical sharing band where the Company absorbs
3 10 percent of the variance outside the deadband, and finally a symmetrical earnings
4 test where the collection or refund of a PCAM variance is limited to amounts that will
5 bring PacifiCorp to within 100 basis points of the Company's authorized return on
6 equity (ROE). Additionally, the amortization of deferred amounts are capped at
7 six percent of the revenue for the preceding calendar year.

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

10 A. No. Despite persistent and significant under-recovery of NPC since the
11 implementation of the PCAM, due to the operation of the deadbands, sharing bands,
12 and earnings test, PacifiCorp's rates have never been adjusted as the result of the
13 PCAM. Notably, for the time period of 2015 to 2019, PacifiCorp has
14 under-recovered approximately \$84 million in Oregon-allocated NPC. The full
15 under-recovery for the past 12 years is shown in Figure 2 below.

FIGURE 2
Oregon NPC Collected in Rates versus Actual NPC

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	347,188,521	132,951
2017	361,522,414	364,689,242	3,166,827
2018	350,555,442	370,884,594	20,329,152
2019	349,907,375	391,754,865	41,847,490

Note: Beginning in 2017, PTCs have been included in the TAM, however, this figure shows the NPC amounts excluding PTCs for consistency with prior years. Additionally, the 2016 Actual NPC include approximately \$4.6 million associated with unusual Bridger Coal costs that would not typically be included in a TAM.

Q. Are the adjustments proposed by the parties consistent with the purpose of the TAM as articulated by the Commission?

A. No. As described above, the purpose of the TAM is to derive the most accurate forecast for setting fair, just and reasonable rates. However, as shown in Figure 2 above, PacifiCorp has systematically under-recovered NPC when comparing the TAM to the PCAM. Unfortunately, it appears that many of the adjustments proposed by the parties are not intended to improve the accuracy of the TAM forecast, but rather to perpetuate and even increase PacifiCorp's chronic NPC under-recovery, recognizing that the high bar for triggering the PCAM will not be met. Even when PacifiCorp achieves greater accuracy through methodologies like the DA/RT adjustment, parties continue to attempt to chip away at these methodologies year after year to produce lower but less accurate rates. Most troubling of all, many parties now

1 seem to be using the TAM to attempt to dictate actual operational decisions to
2 PacifiCorp, instead of reviewing the reasonableness of the Company's NPC for
3 ratemaking purposes.

4 **IV. FORECASTING COAL GENERATION**

5 **Q. How does the Generation and Regulation Initiative Decision Tools (GRID)**
6 **model dispatch PacifiCorp's generation resources, including its coal resources?**

7 A. GRID dispatches individual resources on a marginal or incremental cost basis, to
8 optimize the dispatch of the Company's existing system in the most economic, or
9 least-cost, manner while accounting for constraints.

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

12 A. To accurately forecast coal costs, the Company models its coal plants to simulate
13 their actual dispatch. The Company excludes from its dispatch commitment analysis
14 the cost of coal that is subject to minimum take provisions.

15 **Q. Please briefly describe how PacifiCorp forecasts coal generation volumes for the**
16 **TAM.**

17 A. Coal generation volume in the forecast is determined by GRID, the Company's
18 hourly dispatch model, under various operational constraints. The GRID
19 optimization logic calculates how the available coal resources should be dispatched
20 given load requirements, transmission constraints and market conditions, and whether
21 market purchases or sales should be made to balance the Company's system. Coal
22 generation attributes, such as nameplate capacity, normalized outage and maintenance
23 schedules, and the calculated available capacity of each unit for each hour are inputs

1 to the model. GRID then determines the hourly generation between minimum and
2 maximum operation level based on a comparison of operating cost versus other
3 resources and the market price.

4 **Q. What are contractual minimum take provisions?**

5 A. As explained in greater detail by Mr. Ralston and Mr. Schwartz, contractual
6 minimum take provisions provide for a minimum payment to be due if PacifiCorp
7 fails to take the minimum contract volume of coal. The Company pays the full
8 purchase price of the coal if the annual purchases are below the minimum volume
9 required for a certain timeframe such as a contract year.

10 **Q. How are contractual minimum take provisions modeled in GRID?**

11 A. The incremental fuel cost input to GRID consists of only a single value, so multiple
12 pricing tiers are not recognized by the model. For that reason, the Company uses an
13 iterative process to arrive at a marginal fuel cost that produces a result where the
14 generation at each plant meets the minimum coal purchase requirements, i.e. the
15 contractual minimum take provisions, present in the supply contracts. The point is to
16 ensure that customers receive all of the energy associated with the costs charged
17 under the supply agreements.

18 **Q. What are contractual liquidated damages provisions and how are they modeled**
19 **in GRID?**

20 A. As explained in greater detail by Mr. Ralston and Mr. Schwartz, contractual
21 liquidated damages provisions provide for a payment, less than the full price of coal,
22 to be due if PacifiCorp fails to take the minimum contract volume of coal. The
23 Company accounts for liquidated damages in its dispatch analysis by recognizing that

1 these costs will be incurred if the units are not dispatched enough to satisfy
2 contractual minimums.

3 **Q. Please explain how GRID arrives at the optimal economic forecast of coal**
4 **generation volumes considering minimum take requirements.**

5 A. Coal volumes are determined by GRID based on the economic dispatch of each coal
6 plant. As just noted, the dispatch in GRID is a result of logic that only supports a
7 single incremental fuel price input value in the dispatch decision for each coal unit.
8 Consequently, iterative GRID runs may be necessary to ensure that coal burn
9 volumes are consistent with minimum take requirements across the coal fleet. If the
10 coal volumes determined by GRID are below the minimum take requirements at a
11 given coal plant, the incremental coal price input is adjusted down (driving up
12 consumed coal volume as determined by GRID) until the minimum coal volume is
13 achieved or the incremental fuel price reaches approximately zero. The coal volumes
14 in the TAM forecast satisfy both the economic dispatch logic and the minimum take
15 requirement. The Company has used this method in every TAM proceeding and the
16 Commission explicitly affirmed this modeling methodology in the 2017 TAM (docket
17 UE 307).

18 **Q. Please explain how coal generation volumes in the TAM compare to actual**
19 **generation volumes.**

20 A. The level of coal generation used to serve load in actual operations is higher than the
21 amount forecast in the TAM. Figure 3 shows that coal generation has been dropping
22 over the past eight years and, on average, approximately 58 percent of PacifiCorp's
23 total requirement (retail load plus wholesale sales) has been served by its coal fleet.

1 In those same years in the TAM, only approximately 56 percent of PacifiCorp's total
2 requirement was served by its coal fleet. In short, GRID optimizes the coal fleet
3 beyond what is possible in actual operations.

4 **FIGURE 3**

Coal Generation % of Total Requirement			
Year	Actual (MWh)	TAM (MWh)	Difference
2012	60.10%	59.79%	0.31%
2013	62.38%	60.43%	1.95%
2014	60.47%	59.25%	1.22%
2015	60.98%	59.37%	1.61%
2016	56.32%	51.15%	5.17%
2017	56.20%	53.66%	2.54%
2018	54.35%	54.58%	-0.23%
2019	53.32%	47.51%	5.81%
Average	58.01%	55.72%	2.30%

5 **A. Reply to Staff's Recommendations on Coal Unit Forecasting and Economic**
6 **Shutdowns**

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

9 A. Staff offers several specific recommendations related to economic cycling of coal
10 units. First, I provide some background on PacifiCorp's process for the economic
11 cycling of coal units in GRID. Then I discuss how PacifiCorp's "must run"
12 constraint is used in GRID and explain why Staff's recommendations create difficulty
13 in modeling and frustrate the purpose of the TAM. Finally, I address Staff's specific
14 concerns and recommendations on economic cycling.

15 *1. Economic Cycling of Coal Units*

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

17 A. In the 2018 TAM, Staff proposed an adjustment intended to model the economic

1 cycling of coal plants, which had occurred in limited historical circumstances based
2 on unusual market conditions in 2016 and 2017. The Commission rejected Staff's
3 adjustment. In doing so, the Commission noted that it reviews "GRID dispatch issues
4 to determine whether the Company is meeting its obligation to operate prudently,
5 with prudent unit commitment and dispatch decisions that minimize costs."⁸ The
6 Commission then found that "PacifiCorp has explained that its current GRID
7 modeling reflects historic, normalized practices regarding economic shutdowns of
8 coal units."⁹ Noting that PacifiCorp's operations may be responding to evolving
9 market conditions, the Commission expressed an interest in understanding how
10 PacifiCorp's operations may be changing.¹⁰ To that end, the Commission directed
11 PacifiCorp to hold a workshop to address economic cycling of coal plants and to
12 make a presentation at a public meeting before the 2019 TAM on the workshop and
13 specifically summarize any proposals identified to increase the accuracy of coal
14 dispatch modeling due to economic outages, among other coal issues.

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

17 A. Yes.

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

20 A. Yes. In response to the Commission's interest and after workshops with Staff and
21 other parties, PacifiCorp proposed modeling economic shutdowns for coal plants that

⁸ Order No. 17-444 at 11.

⁹ Order No. 17-444 at 11.

¹⁰ Order No. 17-444 at 11.

REDACTED

1 are majority-owned by the Company, not participating in the EIM, and not under
2 operational constraints that would preclude an economic shutdown in 2019. Staff
3 agreed with this modeling approach and the Commission approved a stipulation that
4 included PacifiCorp's proposal for modeling economic cycling of coal plants. In the
5 2019 TAM, Staff specifically testified that the "number of hours of economic cycling
6 in PacifiCorp's forecast is [REDACTED] PacifiCorp's historic cycling hours," which
7 Staff testified "lends credibility to PacifiCorp's forecast, but raises additional
8 concerns that PacifiCorp's actual cycling decisions may be less than optimal."¹¹ Staff
9 continued: "PacifiCorp's actual cycling decisions are a PCAM issue, not a TAM
10 issue, and parties should address PacifiCorp's actual operation cycling decisions in
11 the next PCAM."¹²

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

14 A. Yes. The Company made no changes to the modeling that was agreed to and
15 approved in the 2019 TAM settlement. In the 2020 TAM, Staff disputed the
16 Company's modeling, but again acknowledged that that the Company's method for
17 modeling economic cycling produces more economic cycling hours than are realized
18 in actual operation.¹³ Staff ultimately entered into a stipulation that did not change
19 the economic cycling modeling. The Commission approved the settlement.

¹¹ Docket UE 339, Staff/200, Kaufman/8.

¹² Docket UE 339, Staff/200, Kaufman/8.

¹³ Docket UE 256, Staff/300 Enright 17.

1 **Q. Did the Company change how it models economic cycling of coal plants in the**
2 **2021 TAM?**

3 A. No. The Company used the same modeling that was used in the 2019 and 2020
4 TAMs. In this case, the economic cycling of coal plants reduced total Company NPC
5 by approximately \$42,000 in the initial filing.¹⁴ The lower forecasted NPC reduction
6 in the 2021 TAM is caused, in part, by the permanent closure of Cholla Unit 4.

7 **Q. How does the Company model economic cycling in the TAM?**

8 A. The cycling period (*i.e.*, when a coal unit could be shut down for economic reasons)
9 runs from February 1 to May 31, which corresponds to the spring hydro run-off
10 period when loads are generally lower, weather is typically mild, market prices are
11 typically lower, and solar imports from California are increasing.

12 Under the Company's modeling, the "must run" setting in GRID for the
13 eligible coal plants is removed and these plants are dispatched based on economics
14 during the cycling period. The eligible coal plants incorporate the minimum up time,
15 minimum downtime and startup costs as part of the economic dispatch parameters.
16 The number of startups during the entire cycling period is limited to no more than
17 four.

18 **Q. What are the results of the Company's economic cycling modeling and how do**
19 **the results compare to actual coal operation experiences?**

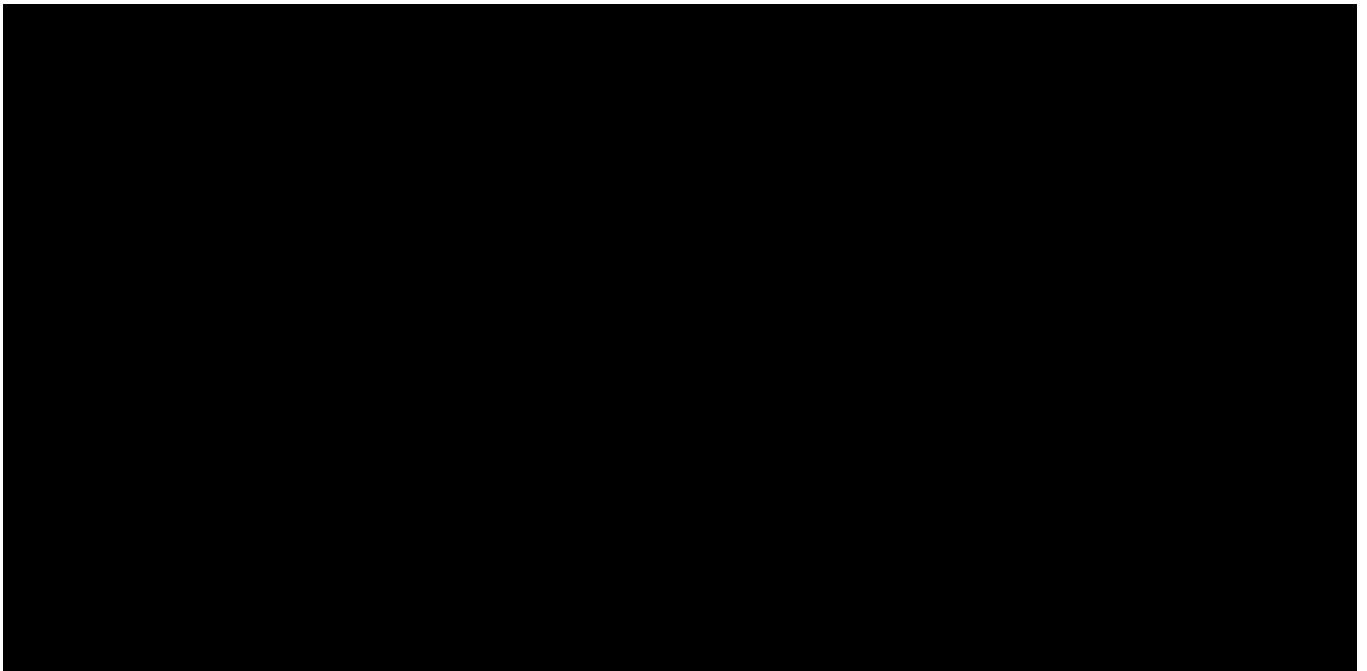
20 A. Confidential Figure 4 below compares the actual coal unit economic cycling for the
21 years 2016 to 2019, compared to the amounts forecasted in the TAM for 2019 to
22 2021. Due to the retirement of Cholla Unit 4 at the end of 2020, all Cholla Unit 4

¹⁴ PAC/100, Webb/18.

REDACTED

1 economic cycling hours have been removed from the data to provide an “apples-to-
2 apples” comparison. The table below shows the 2021 TAM forecast results in coal
3 plants being offline for [REDACTED] hours or approximately [REDACTED] megawatt-hours
4 (MWh) which is roughly equivalent to the number of hours as the actual economic
5 cycling hours in [REDACTED], the year with the highest number of economic cycling hours in
6 the past five years. Based on the forecasted market price and market conditions,
7 PacifiCorp believes the coal economic cycling forecast for the 2021 TAM will more
8 than capture the possible economic cycling of coal units during 2021.

9



10 **Q. Does the Company’s method for modeling economic cycling produce more**
11 **economic cycling hours than are realized in actual operation?**

12 A. Yes. Modeling economic cycling in GRID under normalized assumptions with
13 perfect foresight in a one year forecast can result in higher economic cycling hours
14 than can be realized in actual operation. This fact suggests that coal units on the
15 system are not only used to serve load but also used as system resources for reliability

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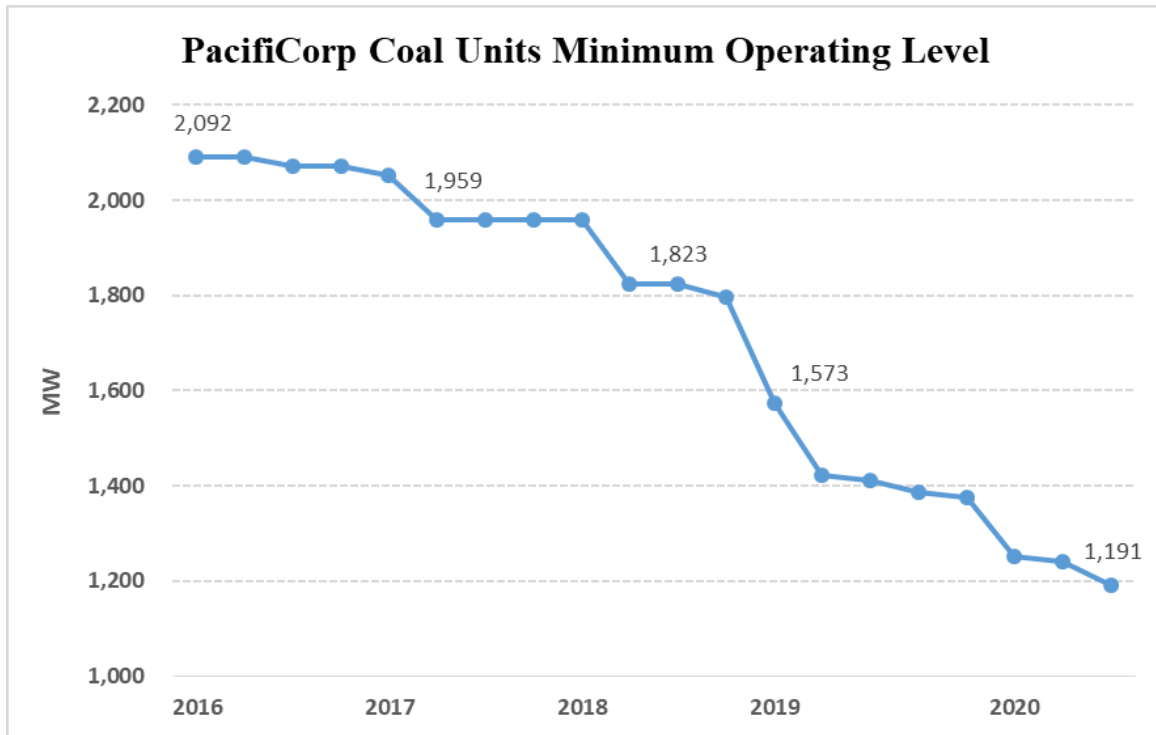
1 when dispatching in actual operations. As shown in Confidential Figure 4, the
2 forecast in the TAM for 2019 cycling called for [REDACTED] hours of offline time and
3 approximately [REDACTED] million avoided MWh. In actual operations, the Company was
4 only able to realize [REDACTED] hours of offline time and approximately [REDACTED] avoided
5 MWh. The average economic cycling hours for the years 2016 to 2019 is only about
6 half of the average hours from the three most recent corresponding TAM years.

7 **Q. Why are the economic cycling hours in 2018 and 2019 substantially lower than**
8 **those in the past years?**

9 A. Beginning in 2017, PacifiCorp has methodically implemented efforts to reduce the
10 thermal generation units' minimum operating levels or minimum generation levels to
11 provide more flexibility in actual operations. Consequently, PacifiCorp's coal unit
12 minimum operating levels are at an all-time low, which has provided a more flexible
13 coal operating profile in actual operations. Figure 5 below shows that the total coal
14 units' minimum operating level has been steadily decreasing since 2016. The total
15 coal unit minimum operating level in 2020 is only 1,191 MW, reduced by almost half
16 compared to the coal unit minimum operating level of 2,092 MW in 2016. This
17 change is discussed in Mr. Mitchell's reply testimony which explains that by
18 decreasing minimum operating levels, the Company has created more value for
19 customers than is possible through economic cycling.

1

FIGURE 5



2 **Q. Does Staff recommend changes to the modeling of coal plants even though GRID**
3 **is already producing more economic cycling than is achieved in actual**
4 **operations?**

5 **A.** Yes. Staff claims there are additional potential savings that can be realized by
6 relaxing the parameters around which economic cycling is modeled.¹⁵ Staff suggests
7 that modeling more economic cycling in the TAM will lead to more economic
8 cycling in actual operations because, according to Staff, the “TAM filing informs the
9 Company’s actual operations by providing financial targets for their performance.”¹⁶

¹⁵ Staff/200, Enright/12.

¹⁶ Staff/200, Enright/10.

1 **Q. Does the Company use the TAM filing as a “financial target” as Staff suggests?**

2 A. No. The Company has never used the NPC set in ratemaking proceedings, like the
3 TAM, as a target for actual operations. Therefore, artificially decreasing the
4 forecasted NPC as some sort of incentive for actual operations is misguided.

5 2. *The “must run” setting in GRID*

6 **Q. Please describe Staff’s concerns and recommendation regarding the “must run”
7 setting in GRID.**

8 A. Staff claims that the “must run” setting in GRID is an unnecessary restriction on the
9 Company’s coal units. Staff maintains that removing the setting will alleviate or
10 resolve concerns it has about modeling of shutdowns and planned outages together,
11 the economic cycling period, and shutdowns for exclusively non-EIM participating
12 units. Staff recommends removing the setting from all of the Company’s coal plants
13 for every month of the year.¹⁷

14 **Q. Please explain what the “must run” setting is and why the Company includes
15 this setting for coal units in GRID.**

16 A. The “must run” setting for coal units in GRID is used to represent actual operational
17 practice as closely as possible for normalized ratemaking purpose. In regulatory
18 ratemaking, the forecasted NPC is set on a normalized basis. GRID is designed to
19 model the NPC with load, market conditions, prices, generation resources, and
20 operating practices under normal condition. Cycling coal units happens infrequently
21 in actual operations, therefore, coal units in GRID are modeled as closely to how they
22 are designed in actual operations, as base load units, i.e., “must run.”

¹⁷ Staff/200, Enright/15.

1 **Q. Please explain how the “must run” setting reflects actual operations.**

2 A. In actual operations, the Company would not entirely shut down a coal unit for a short
3 period of time when its dispatch price might be higher than other resources for several
4 reasons.

5 First, the “must run” setting avoids additional start-up costs that would be
6 incurred if the units were entirely shutdown. The minimum stable run levels are now
7 low enough at most of the Company’s coal fired generation plants that a comparison
8 of avoided fuel costs against start-up costs almost never weighs in favor of cycling
9 outside of the spring runoff season.

10 Second, entirely shutting down a coal unit creates reliability risks because it
11 takes so long to start a coal unit once it is entirely shut down. As PacifiCorp has
12 explained in prior TAMs, determining whether a coal unit can be shutdown requires
13 consideration of more than just economics. PacifiCorp also considers transmission
14 congestion, voltage support, and other operational issues such as maintaining
15 adequate system inertia. For example, the Jim Bridger units provide a substantial
16 amount of operational flexibility to the entire Company system. The Jim Bridger
17 units have the ability to provide regulating reserves to both the east and west
18 balancing authority areas (BAA). In 2016, the Jim Bridger units and two other coal
19 units held nearly 80 percent of the regulating reserve on the system. The Jim Bridger
20 units are also the primary supply of frequency responsive reserves for the PacifiCorp
21 West (PACW) BAA. When one or two Jim Bridger units are offline, the system
22 planning for single outage contingency and subsequent multiple outage contingency
23 are magnified. Given the lowered minimum operating levels and an increasing

1 quantity of low-priced renewable energy coming from the EIM market, coal
2 generation is an essential resource type to provide both economic and reliable
3 electricity and balance load, meet operational requirements, and comply with North
4 American Electric Reliability Corporation (NERC) regulation standards.

5 For these reasons, in its actual, prudent operations, the Company will typically
6 cycle a coal unit to its minimum but will not entirely shut it down. As discussed
7 above, the purpose of the TAM is to model actual operations. Removing the “must
8 run” setting departs from actual operations and makes GRID’s overly optimized unit
9 dispatch even more unrealistic.

10 **Q. Please explain the modeling complications of removing the must-run setting in**
11 **the TAM.**

12 A. When coal units are permitted to cycle off in GRID, each unit will need to be
13 subjected to an additional commitment screening process similar to the natural gas
14 units in order to duplicate the methodology for determining unit commitment.
15 Screening is a process the Company uses to produce an optimal commitment for the
16 thermal units in all the hours for the entire forecast period. It applies to any units that
17 are permitted to cycle, which currently only includes natural gas units.

18 The Company could not extend the screening process to coal units without
19 building a new process compatible with its natural gas screening process. This would
20 be a major undertaking because the decision to economically cycle each coal unit is
21 unique. At present, PacifiCorp uses a screening process for its natural gas units
22 because under normal conditions, those units regularly cycle off and on for economic
23 reasons in actual operations. Thus, the screening process conforms GRID to actual

1 operations. This is not the case for coal units because, as discussed above, PacifiCorp
2 does not regularly cycle them.

3 Additionally, coal units are subject to a supply curve. The coal supply curve
4 directly impacts the coal dispatch tier prices and the pricing tier prices. Coal
5 consumption has historically been determined by GRID based on the economic
6 dispatch of the coal unit between its minimum and maximum outputs. If coal units
7 were to be subject to a similar screening process as the natural gas units, then the coal
8 supply curve would have to be taken into account, including minimum take
9 requirements, which would greatly complicate the process.

10 Finally, the natural gas screening process is currently an out-of-model
11 schedule that was developed with an embedded assumption that coal units would not
12 be cycling in the same way that natural gas units do and would be ready to pick up
13 any reserve shortfall when necessary. If coal unit screening is implemented, it would
14 need to occur before the natural gas unit screening because of the fact that coal units
15 are typically lower in the dispatch merit order stack and therefore the coal unit
16 screening will impact the subsequent natural gas unit screening.

17 **Q. Are there any other impacts of removing the “must run” setting that could not**
18 **be captured in GRID?**

19 A. Yes. When a coal unit is offline it reduces the Company’s ability to participate in the
20 EIM. Because EIM benefits are not reflected in GRID, there would be fewer benefits
21 and therefore additional increases to NPC that are not reflected in the GRID run
22 discussed above.

1 **Q. Staff also suggests that planned outages could be combined with economic**
2 **shutdowns to provide additional customer benefits.¹⁸ How do you respond to**
3 **this testimony?**

4 **A. First, as noted above, GRID is already modeling more economic shutdowns than**
5 **occur in actual operations. So, there is no need to further increase GRID’s ability to**
6 **model economic shutdowns to accurately calculate NPC.**

7 **Q. To address the issues discussed above, Staff recommends that the Company**
8 **remove the “must run” setting in the GRID model.¹⁹ Is this reasonable?**

9 **A. No. To more accurately reflect actual operations, the GRID model includes reduced**
10 **minimum operating levels for coal plants. This means that instead of entirely shutting**
11 **down a unit, GRID instead dispatches the unit to its minimum operating levels. For**
12 **the Company’s coal units, the minimum operating levels are very low and for many**
13 **units, the settings have been lowered compared to prior years. As seen in Figure 6,**
14 **the minimum operating level in the 2021 TAM dropped almost 200 MW for the**
15 **following coal units.**

¹⁸ Staff/200, Enright/21-22.

¹⁹ Staff/200, Enright/15.

FIGURE 6

Minimum Operating Level (MW)			
Units	2021 TAM	2020 TAM	Change
Dave Johnston 4	150.0	180.0	-30.0
Hunter 1	70.3	79.7	-9.4
Hunter 2	51.3	78.4	-27.1
Hunter 3	60.0	72.0	-12.0
Huntington 1	70.0	80.0	-10.0
Jim Bridger 1	33.3	80.0	-46.7
Jim Bridger 2	26.7	53.3	-26.6
Jim Bridger 3	43.3	80.0	-36.7
Total			-198.5

Q. Does Staff's proposed adjustment to remove the must-run setting frustrate the purpose of the TAM?

A. Yes. The fact that GRID already models more economic cycling than occurs in actual operations demonstrates that GRID is already overly optimizing coal plant dispatch relative to what can occur in actual operations. Driving down NPC by cycling off more coal plants will only decrease the accuracy of the TAM by disconnecting it from the reality of actual system operation.

Driving down NPC is particularly troubling when the Company has persistently under-recovered actual NPC for so many years, as discussed above. Given this persistent under-recovery, there is no reason to intentionally decrease NPC as some sort of incentive to change actual operations, which appears to be Staff's motivation in recommending changes to coal plant modeling.

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Webb/28

3. *Economic Cycling Period*

Q. Please describe Staff's position on the four-month period of economic cycling in GRID.

A. Staff claims PacifiCorp can attain additional benefits by modeling economic cycling for the entire year, not just during the traditional period of February 1 to May 31.²⁰

Staff states that [REDACTED] of the economic cycling hours and 49 percent of the incidents occurred outside the traditional economic cycling period for the past four years.²¹

Q. Does the Company agree with Staff's analysis of economic cycling?

A. No. Staff analyzed the details of economic cycling carried out by any Company plant for the period 2016 through 2019. Staff considered economic cycling as any unit whose event type is classified by NERC as a reserve shutdown. Of the reserve shutdowns analyzed by Staff, [REDACTED] followed or preceded a maintenance or a planned outage. These very short extensions of maintenance-related outages (a few hours or days) are not the same as a one-or-two month shutdown of a plant for economic reasons.

PacifiCorp periodically extends outages for several hours or days for various operational reasons, including if there is no immediate need to bring the unit back online when the outage is over. Extending an outage for several additional hours should not be included in Staff's analysis of actual economic cycling.

After removing shutdowns that followed or preceded an existing outage, only

[REDACTED] of reserve shutdowns occurred outside the traditional economic cycling

²⁰ Staff/200, Enright/14.

²¹ Staff/200, Enright/14.

REDACTED

PAC/500

Webb/29

1 period during 2016 through 2019. This is compared to the [REDACTED] computed by
2 Staff.

3 *4. Economic Cycling for EIM Participating Units*

4 **Q. Staff is also critical of the Company's modeling that limits economic cycling to**
5 **only those units not participating in the EIM.²² How do you respond?**

6 A. Staff's proposal presumes there are more benefits to economically cycling units
7 instead of offering the units into the EIM. But the EIM automatically finds the
8 lowest-cost energy to serve real-time customer demands for participating units. For
9 example, if going into the hour a coal unit is dispatched above its minimum, the EIM
10 can dispatch the plant down to its minimum to import lower cost energy thus reducing
11 NPC for customers. It does not make sense to economically cycle EIM participating
12 units because the EIM is already producing the lowest cost energy for customers.
13 Moreover, if units that are currently generating EIM benefits were shut down instead,
14 NPC would increase because of lost EIM benefits.

15 **Q. Staff also claims that the Company has economically cycled EIM participating**
16 **units and therefore allowing GRID to model economic cycling for EIM units will**
17 **make the forecast more precise.²³ Do you agree?**

18 A. No. Of the three EIM participating units that were economically cycled units in 2018,
19 the Jim Bridger 3 and Dave Johnston 4 shutdowns either preceded or followed a
20 maintenance outage, which means these should not be considered actual economic
21 cycling. The Hunter 3 shutdown was an isolated instance and that shutdown was only

²² Staff/200, Enright/15-16.

²³ Staff/200, Enright/16.

1 six days which is not comparable to a one-or-two month shutdown of a plant for
2 economic reasons.

3 Moreover, the fact that GRID is already modeling more economic cycling
4 than actually occurs does not mean that increasing economic cycling will make GRID
5 “more precise.” On the contrary, Staff’s recommendation will artificially drive down
6 forecasted NPC. Staff produced no evidence that GRID’s modeling is removing a
7 potential customer benefit that would occur if there were more economic cycling in
8 the forecast.

9 *5. Economic Cycling for Non-Majority Owned Units*

10 **Q. Please respond to Staff’s proposal that PacifiCorp model economic cycling for**
11 **non-majority owned units.²⁴**

12 A. Staff recommends that the Commission require the Company report on its
13 engagement with its co-owners regarding the potential for economic cycling and
14 submit a progress report to the Commission by January 1, 2021.

15 **Q. How do you respond to this recommendation?**

16 A. The Company disagrees with Staff’s recommendation. The decision to economically
17 cycle each unit depends on factors that are unique to each owner. Therefore, working
18 with joint owners to predict economic cycling would be complex, time-consuming,
19 and non-conclusive. Each owner has different economic needs and load obligations,
20 so coordinating economic cycling with other owners is not practical. The Company
21 has had conversations with co-owners of its minority-owned plants as indicated in
22 OPUC Data Request 11, but due to differing system load and market dynamics no

²⁴ Staff/200, Enright/17-18.

1 agreement on shutdowns was possible.²⁵ Staff's recommendation goes beyond the
2 scope and purpose of the TAM and attempts to dictate actual operations to PacifiCorp
3 without considering actual operational constraints.

4 *6. Limitations on Start-ups in economic modeling*

5 **Q. Staff further recommends that the Company remove the limit on the number of**
6 **start-ups used in the modeling of economic cycling.²⁶ How do you respond?**

7 A. This limit doesn't impact the GRID dispatch because it is performed after all the coal
8 units are dispatched by GRID. This is a reasonable condition to maintain economic
9 cycling within a feasible range in consideration of long-term coal unit maintenance
10 expense.

11 **Q. Staff also recommends that the Commission require PacifiCorp to conduct a**
12 **comprehensive study into the non-fuel costs and savings of economic cycling by**
13 **January 1, 2021.²⁷ How do you respond?**

14 A. PacifiCorp does not object to providing additional information, but it is unclear how
15 the Company would perform Staff's recommended study or what useful information
16 would be provided. First, it is difficult to define what are the non-fuel costs and
17 savings of economic cycling as mentioned by Staff. Second, the Company only
18 economically cycles coal units in rare circumstances. If there are any non-fuel cost
19 savings achieved from economic cycling, those savings would be hypothetical and
20 not provide meaningful direction to actual operation or GRID modeling in the TAM.

²⁵ Staff/204, Enright/3.

²⁶ Staff/200, Enright/19.

²⁷ Staff/200, Enright/20.

1 7. *Reporting on Uneconomic Operations*

2 **Q. Staff also recommends that the Company file quarterly reports with the**
3 **Commission that “provide details of any instances of uneconomic operations at**
4 **its coal plant[s], specifically when production costs are above the market price of**
5 **energy.”²⁸ How do you respond?**

6 A. The Company objects to Staff’s recommendation. Staff already has a venue in which
7 they are able to review the Company’s operations: the PCAM filing. Actual
8 operations should inform the forecast methodology in the TAM, but Staff hasn’t
9 provided any indication of how this report relates to the TAM itself. Furthermore, as
10 discussed in more detail in my response to Sierra Club, the Company disagrees with
11 Staff’s premise that it is necessarily uneconomic to dispatch coal plants when average
12 production costs are above the market price of energy. Comparing the average
13 production cost to the market price of energy is not a meaningful comparison and
14 does not demonstrate that it is uneconomic to dispatch a coal plant.

15 **B. PacifiCorp’s Reply to Sierra Club**

16 **Q. Please provide a general overview of Sierra Club’s testimony and**
17 **recommendations.**

18 A. Sierra Club offers several specific recommendations for adjusting the 2021 TAM
19 NPC forecast and several broader recommendations for future changes to NPC
20 modeling, each of which is discussed in detail below. Most of Sierra Club’s claims
21 and analysis, however, boil down to one recommendation—Sierra Club wants the

²⁸ Staff/200, Enright/12.

1 Commission to require PacifiCorp to dispatch its coal units based on the average
2 price, rather than the incremental price.

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

4 A. In the NPC forecast, for off-system sales and for bids into the EIM, PacifiCorp uses
5 the incremental cost rather than average costs of production. This is the most cost-
6 effective approach for customers and results in the most economic unit dispatch, as
7 explained in detail by Company witnesses Mr. Ralston and Mr. Schwartz. Sierra
8 Club's arguments to the contrary rely on false comparisons, overly simplistic
9 analyses, and disregard of established economic principles. To decrease coal
10 generation, Sierra Club recommends both cost disallowances and highly
11 unconventional dispatch practices that would increase costs for customers. Through
12 its IRP, PacifiCorp is accomplishing the same objective—decreased coal
13 generation—in a methodical and cost-effective manner for customers. Sierra Club's
14 recommendations should be rejected as both unnecessary and harmful to customers.

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

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

1 Furthermore, in PacifiCorp's 2013 IRP, only 1.5 percent of PacifiCorp's
2 resource capacity came from renewable resources.²⁹ In contrast, the 2019 IRP
3 projects 33 percent of PacifiCorp's resource capacity in 2021 to come from renewable
4 resources.³⁰ Similarly, PacifiCorp's coal-fired generation, as projected by the IRP,
5 will drop from 53 percent to 31 percent of its resource capacity mix during this same
6 timeframe.³¹

7 *1. Use of Incremental Cost for Dispatch*

8 **Q. What is the incremental cost of production?**

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

14 **Q. What is the average cost of production?**

15 A. The average cost of production is the ratio of the total cost of production to the total
16 energy produced. For example, if a generation unit serves 1,000 MWh of retail load
17 and incurs startup costs, fuel costs, operations and maintenance costs (O&M) totaling
18 \$60,000, then the average cost of production is \$60/MWh. For purposes of a coal
19 unit, the average cost of production would consider minimum take provisions, if
20 applicable.

²⁹ PacifiCorp's 2013 Integrated Resource Plan at 229 (Apr. 30, 2013).

³⁰ PacifiCorp's 2019 Integrated Resource Plan at 257 (Oct. 18, 2019).

³¹ *Id.*

1 **Q. Why does PacifiCorp not utilize the average cost pricing Sierra Club relies on**
2 **when creating short-term NPC forecasts for the TAM?**

3 A. Incremental cost dispatch lowers NPC. Sierra Club's reliance on average costs
4 presumes away the impact of minimum take contract provisions, which, as described
5 by Mr. Schwartz, are not something the Company can avoid in a coal supply
6 agreement. The cost of coal in a minimum take volume tier is a previously incurred
7 cost, as the cost for that volume is going to be incurred whether the coal is burned or
8 not. As a result, the incremental (or marginal) cost of generation in that price tier is
9 zero. Because minimum take provisions result in actual fuel costs, if the Company
10 were to reject that fuel and instead purchase energy on the market or replace the coal
11 generation with an equivalent amount of generation from other sources, it would
12 increase NPC by the value of the replacement fuel or replacement power.

13 **Q. Can you provide an example showing how the use of average price dispatch**
14 **increases NPC?**

15 A. Yes. A more comprehensive study is provided later, but as an example of how
16 average price dispatch would work for wholesale sales or EIM participation, please
17 refer to Figure 7 for an example depicting a plant generating to serve a 100 MW load
18 on the system:

FIGURE 7

	Without Incremental Generation	With Incremental Generation
Fixed Costs	\$800	\$800
Variable Costs	\$1,000	\$1,010
Average Costs	\$18.00	\$17.92
Incremental Revenue	\$0	\$17
Output	100 MW	101 MW
Total Net Costs	\$1,800	\$1,793

This is a simple example, but it illustrates a fairly basic concept. In this situation, the Company would be making a decision between 1) increasing output based on incremental costs, or 2) forgoing that increase along with the incremental revenue that would be generated. The average cost before the increase is \$18/MWh based on fixed costs of \$800, variable costs of \$1,000, and output of 100 MW. The ability to realize incremental revenue of \$17 in exchange for taking on incremental costs of \$10 results in net savings, as shown in the bottom line numbers. Increasing generation is clearly and obviously the cost minimizing option, yet Sierra Club would argue against this approach because the average cost of \$18/MWh is above the incremental revenue of \$17/MWh.

Q. Does Sierra Club provide its own example to illustrate the difference between incremental and average price dispatch?

A. Yes. Sierra Club's testimony offers another example that, if corrected to reflect actual real-world operations, shows the fallacy of Sierra Club's position. Sierra Club offers the following example:

Assume that a small business needs to buy 10 chairs for a new office. When looking at their options, one brand seems to be by far the least expensive, costing only \$50 for a chair. At that point, a decision is made to buy 10 chairs of that brand (or \$500 total). But when the time comes to pay and the business has already

1 committed to buy the chairs, it is revealed that only the tenth
2 chair is available at that price, the first nine cost \$100 each (or
3 \$950 total). Another brand could have been available at \$60 per
4 chair for all 10 chairs (\$600 total), but the decision was made
5 based only on the 1 “incremental” price of the last chair. This
6 would be bad decision-making and bad public policy.³²

7 Applying this example to PacifiCorp, the Company purchased nine chairs for \$100
8 each for a total of \$900 (which is a previously incurred cost that cannot be avoided,
9 like a minimum take provision). To purchase the tenth chair, the Company could pay
10 an additional \$50 or \$60. Obviously, the Company would purchase the tenth chair for
11 \$50.

12 But Sierra Club’s recommendation here is not only that the Company pays
13 \$10 more for the tenth chair, the Company also acquires an additional nine chairs for
14 \$60 each (i.e., the Company displaces coal generation with something else). Sierra
15 Club’s approach would have the Company pay a total of \$1,500: \$900 for the first
16 nine chairs plus \$60 for the tenth chair plus \$540 for another nine chairs.
17 PacifiCorp’s approach would cost only \$950. Sierra Club’s example makes sense
18 only if you assume there are no minimum take provisions, which Mr. Ralston and
19 Mr. Schwartz make clear is not a realistic assumption.

20 **Q. How is it that the average and incremental prices could differ in this example?**

21 A. As previously discussed, the average price includes previously incurred costs, such as
22 start-up charges that are recouped by maximizing output when the incremental value
23 being realized exceeds the incremental cost of production (i.e., when the incremental
24 cost of production is lower than the cost to purchase or generate the same energy
25 from another source). Incremental price dispatch allows the previously incurred costs

³² Sierra Club/100, Burgess/38-39.

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Webb/38

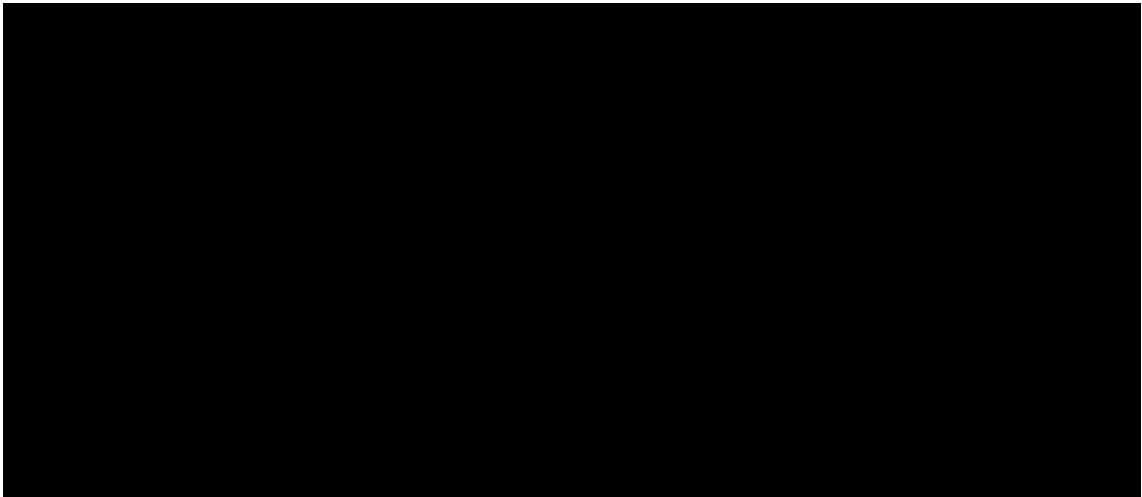
1 to be spread across greater MWh, which reduces the average costs in the process.

2 This is a real-world example of economies of scale. Ignoring this principle would be
3 harmful to Oregon customers.

4 **Q. Has the Company performed any analysis demonstrating the adverse customer**
5 **impact of dispatching using average prices?**

6 A. Yes. To provide a more robust illustration of the hazards of this approach, the
7 Company completed a GRID study to estimate the NPC impact of dispatching the
8 system using average coal prices, as suggested by Sierra Club. The result was an
9 increase of \$60 million on a system-wide basis. The high-level drivers are shown in
10 Confidential Figure 8 below.

11



12 **Q. Please summarize the main drivers behind the increase in NPC in Confidential**
13 **Figure 8.**

14 A. There was a decrease in wholesale sales revenue of approximately \$14 million, an
15 increase in purchased power expense of approximately \$19 million, and an increase in
16 natural gas fuel expense of approximately \$44 million. Those increases were offset by
17 a decrease of approximately \$17 million in coal fuel expense.

1 **Q. Does this study undermine Sierra Club’s premise that its recommendation is in**
2 **customers’ interests?**

3 A. Yes. This example demonstrates the underlying flaws in Sierra Club’s argument and
4 verifies the reasonableness of the Company’s use of incremental pricing to make
5 dispatch decisions. Average cost dispatch causes coal expenses to decline, while
6 natural gas fuel expense increases, market purchases increase to offset a portion of the
7 lost generation, and the Company participates less in the wholesale sales market.
8 These effects decrease coal generation, but increase overall NPC by \$60 million, to
9 the detriment of customers.

10 **Q. Is there anything else that deserves consideration when interpreting the model**
11 **output?**

12 A. Yes. In addition to those top line results, GRID already optimizes the fleet beyond
13 what can be achieved in actual operations, and cannot contemplate the recursive
14 effect of PacifiCorp’s increased buying pressure coupled with reduced supply. In
15 other words, the actual results of acting on Mr. Burgess’ suggestions would very
16 likely be far worse than the GRID forecast.

17 **Q. Sierra Club points out that the Company uses average dispatch cost in its IRP**
18 **modeling and argues that inconsistency shows it is unreasonable to use marginal**
19 **pricing in the TAM.³³ Do you agree?**

20 A. No. There is an important difference in the purposes of the TAM and the IRP. The
21 Company’s IRP uses a 20-year planning horizon and considers the average coal fuel
22 cost in its dispatch commitment. This is appropriate for a long-term resource-

³³ See Sierra Club/100, Burgess/42.

1 optimization study, but not for a shorter-term production-cost forecast like the TAM.
2 The Company completes the IRP to inform long-term resource decisions, which
3 include decisions that can change the future composition of the Company's
4 generation fleet or the system topology. In short, it is a model that is run to determine
5 whether to invest in new resources, to expand transmission capabilities, or to retire a
6 generation asset. It is a comprehensive analysis that considers future capital
7 deployments and expenses and evaluates several possible outcomes over a vastly
8 different time horizon. Shorter-term forecasts like the TAM view the generation fleet
9 and topology as fixed in place, so the focus is on cost-based dispatch optimization
10 using incremental fuel costs. These are fundamentally different studies performed for
11 different reasons in order to answer different questions about the future of the
12 Company.

13 2. *Displacement of Coal Resources*

14 **Q. Sierra Club claims that it reviewed PacifiCorp's GRID model to identify coal**
15 **units that generate even when other lower-cost alternatives were available.**
16 **What does it claim this review shows?**

17 A. Sierra Club claims that three of the Company's coal plants, Jim Bridger, Naughton,
18 and Hayden dispatch at a higher fuel cost per MWh than other Company-owned coal
19 plants, natural gas plants, short-term firm purchases, and/or renewable energy
20 resources.³⁴

³⁴ Sierra Club/100, Burgess/16-17.

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Webb/41

1 **Q. Why does Sierra Club claim that Jim Bridger, Naughton, and Hayden's**
2 **generation and costs are excessive?**

3 A. In Table 2 on page 15 and Table 3 on page 17 of his testimony, Mr. Burgess utilized
4 data provided from the workpapers supporting Exhibit PAC/104, for the 2021
5 forecasted NPC, to calculate the average cost per MWh of PacifiCorp's coal units and
6 alternatives. The Jim Bridger, Naughton, and Hayden coal plants had an average cost
7 of [REDACTED]/MWh, [REDACTED]/MWh, and [REDACTED]/MWh respectively³⁵ for the 2021 test
8 period, which was higher than PacifiCorp's natural gas fleet cost of [REDACTED]/MWh and
9 a Wyoming wind cost of \$17.08/MWh.³⁶ Sierra Club also claimed that short-term
10 firm purchases are lower than the cost of the above mentioned coal plants, which is
11 incorrect. The average short term firm purchases is actually [REDACTED]/MWh in the 2021
12 TAM. Sierra Club suggests that because the average \$/MWh of these alternatives are
13 lower than the average \$/MWh of the Jim Bridger, Naughton, and Hayden coal
14 plants, the Company's projected generation of the Jim Bridger, Naughton, and
15 Hayden units is excessive.

16 **Q. Is this claim accurate?**

17 A. No. Sierra Club's simplistic analysis includes only a portion of the applicable costs
18 and ignores all supply constraints as discussed by Mr. Ralston and Mr. Schwartz.

³⁵ Sierra Club/100, Burgess/17.

³⁶ Sierra Club/100, Burgess/17.

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1 **Q. Sierra Club claims that “if the forecasted generation from Jim Bridger and**
2 **Hayden was reduced to a level where they simply consumed their minimum take**
3 **contract quantities, but no more, and the rest was replaced with wind, this**
4 **would result in net NPC savings of [REDACTED].” It adds that “absent the**
5 **minimum take contract provisions present in current coal supply agreements for**
6 **these plants, these savings could be on the order of [REDACTED].”³⁷ Please explain**
7 **why Sierra Club’s analysis is flawed.**

8 **A. This analysis fails to consider all NPC. Sierra Club’s analysis considers only the**
9 average fuel costs at Jim Bridger and Hayden and an average market purchase price.
10 In creating an optimal system dispatch, however, one must consider many other
11 variables. The Company’s goal in determining optimal dispatch and forecasting NPC
12 is to minimize power costs holistically over the forecast period (one-year in the
13 TAM). The adjustment Sierra Club calculates uses the annual average market
14 purchase price but does not take into account the shape of that market price, meaning
15 PacifiCorp would likely have to purchase more energy in higher priced time periods.
16 There is also no consideration that market prices would potentially increase or market
17 liquidity issues may arise if PacifiCorp were forced to purchase these additional
18 quantities.

19 Additionally, Sierra Club’s adjustment does not consider any of the potential
20 operational impacts such as system reliability, ability to hold reserves, transmission
21 constraints, voltage support, and maintaining adequate system inertia.

³⁷ Sierra Club/100, Burgess/18.

1 **Q. Are there any other problems with Sierra Club’s claim that PacifiCorp has**
2 **access to lower cost resources that could be used to displace coal generation?**

3 A. Yes. Sierra Club’s simplistic approach relies exclusively on price to claim that
4 PacifiCorp could swap out coal with alternative resources. For example, Sierra Club
5 repeatedly claims that wind generation could replace coal generation.³⁸ But wind
6 generation is non-dispatchable, meaning that the Company cannot control the timing
7 of wind output and cannot shape the output to meet demand. The intermittent nature
8 of wind resources adds uncertainty to the system operation. The existence of wind
9 resources on the system diminishes the forecasted output of the Company’s coal
10 resources (which is evidenced in the TAM forecast itself when compared to prior year
11 forecasts), but it does not obviate the need for them to contribute energy and
12 operational capabilities such as reserves.

13 Moreover, the full volume of forecasted wind generation for the test period is
14 represented in GRID as a fixed position—meaning all of the Company’s wind
15 generation (including the Energy Vision 2020 resources) is already used by the model
16 and has already displaced as much coal generation as is economically and
17 operationally feasible. Because wind has no incremental cost, GRID will always
18 select wind over coal, or any other resource with a non-zero incremental cost. So if
19 the Company’s forecasting indicated higher wind generation, it would already be
20 accounted for in GRID. In short, the wind generation Sierra Club suggests could
21 displace coal does not exist. Thus, Sierra Club is left essentially arguing that the
22 Company should acquire new wind resources—over and above the Energy Vision

³⁸ Sierra Club/100, Burgess/18.

1 2020 resources—and have those resources operational by 2021 to displace coal. Such
2 a recommendation is entirely unreasonable for the TAM and reflects the fact that
3 Sierra Club has improperly conflated long-term resource planning with short-term
4 NPC forecasting.

5 **Q. Could the Company rely on market purchases to offset a substantial portion of**
6 **the Company's coal generation?**

7 A. No, not on an annual basis. The Company can modify its dispatch plans over a
8 limited horizon in order to replace some generation with purchased power, but market
9 purchases lack the operational flexibility provided by generating resources. That
10 operational flexibility is critical in maintaining system stability. GRID balances with
11 perfect foresight in any increment for each individual hour in the forecast period,
12 which is more perfect optimization than can be achieved in actual operations.
13 Therefore, while it would appear in GRID that market purchases could be used to
14 continuously balance load, it's simply not feasible in actual operations.

15 **Q. Are there any other problems with Sierra Club's claim that other resource**
16 **options could displace coal generation during the 2021 test period?**

17 A. The TAM is an annual NPC adjustment mechanism, not a long-term strategic analysis
18 such as the IRP. If the continued operation of a coal unit is selected as part of the
19 preferred portfolio in the IRP, then PacifiCorp develops specific strategies and plans
20 to provide the least-cost, least-risk fueling plan for that unit.

21 Neither the 2017 IRP nor the 2019 IRP indicates that the Jim Bridger plant,
22 the Naughton plant, or the Hayden plant should be shut down or significantly
23 curtailed over the 2021 period covered by the TAM. Therefore, there is no basis to

1 assume, as Sierra Club does, that a shut-down or curtailment of any one of these
2 plants is favorable to customers. The 2019 IRP does contemplate early retirement of
3 existing coal resources such as Cholla Unit 4 in 2020, Jim Bridger Unit 1 in 2023, and
4 Naughton Units 1 and 2 in 2025. This is in addition to the recent retirements of
5 Carbon Units 1 and 2 in 2015 and the conversion of Naughton Unit 3 in 2019. These
6 plans are part of the Company's continual evaluation of opportunities to create a
7 robust and diverse generation resource mix in order to provide customers with
8 affordable, reliable and clean sources of electricity.

9 **Q. Is there a more measured and reasonable way to displace coal generation and**
10 **replace it with wind power?**

11 A. Yes, and the Company is already underway on those plans. As part of the Energy
12 Vision 2020 initiative, PacifiCorp has repowered most of its wind generation facilities
13 and will be repowering the remaining wind generation facilities, building new wind
14 generation resources, and expanding transmission capabilities to get that newly
15 available power to market or customers. The expected completion timeframe is the
16 fourth quarter of 2020. The decision to undertake Energy Vision 2020 was made
17 during the 2017 IRP, and most repowering facilities have already been approved in
18 the Company's renewable adjustment clause filing and the remaining resource is
19 being addressed in the Company's current general rate case. The IRP is the
20 appropriate forum for formulating the analysis and discussions centered on long-term
21 resource planning such as the displacement of coal generation, not the TAM.

22 The approach chosen by the Company retains dispatchable resources that
23 provide the operational flexibility required for demand and frequency response,

1 which cannot be achieved through reliance on market purchases or intermittent
2 generation resources. However, this approach also reduces the output from those
3 dispatchable resources, which frees them to hold reserves and serves to reduce both
4 coal expense and natural gas expense.

5 **Q. What are the anticipated impacts of Energy Vision 2020 on NPC?**

6 A. In short, the Company expects a reduction in coal consumption and overall NPC after
7 project completion. For the purpose of providing an estimate, a GRID study was
8 performed forecasting system dispatch as if Energy Vision 2020 was not scheduled
9 for completion until after 2021. The result was that overall coal generation increased
10 by eight percent as expected since the scenario contemplates the removal of
11 significant zero fuel-cost renewable generation currently included in the TAM
12 forecast. Overall NPC also increased by approximately 6.4 percent or \$90 million on
13 a total-company basis, with the majority of the increase attributable to a \$58 million
14 increase in coal fuel expense, a \$25 million increase in purchased power expense, and
15 a \$7 million increase in natural gas fuel expense. In addition to all of those NPC
16 impacts, the Company would also lose approximately \$81.6 million of PTCs, which
17 would also serve to increase rates for Oregon customers. Note that unlike the actions
18 proposed by Sierra Club, the course of action chosen by the Company produces actual
19 savings when compared to a scenario that doesn't contemplate the Energy Vision
20 2020 project because the more deliberate approach taken by the Company identified
21 topological changes to the system that were required in order to make it succeed in
22 reducing NPC for customers. This comparison of the two methodologies again shows
23 the hazards of superficial analysis and illustrates that the Company is already

1 deploying capital when such expenditures are shown to be prudent and beneficial to
2 customers in the long-term studies that accompany the development of an IRP.

3 **Q. Sierra Club also relies on coal unit capacity factors and claims that PacifiCorp is**
4 **uneconomically dispatching its coal units because high cost units also have high**
5 **capacity factors.³⁹ Is Sierra Club’s analysis meaningful?**

6 A. No. Sierra Club has once again conflated incremental and average costs, while
7 attempting to ignore legitimate, prudent, industry standard contract provisions that
8 have withstood close regulatory scrutiny in several past proceedings. They also
9 provide no analysis whatsoever accounting for physical constraints of any kind. They
10 simply mention them and then presume that those drivers should not alter the
11 outcome “under most circumstances.”⁴⁰ However, that is not the case at all. For an
12 exceedingly simplified example, take a situation where the Company has an
13 extremely affordable generation source that cannot reach loads or markets, and an
14 extremely expensive one that can reach either or both. Obviously, the more
15 expensive unit would run more often since transmission constraints would make
16 dispatching the more affordable resource a futile effort. Again, this is an extreme
17 example that has no counterpart in the Company’s modeling of the system, but it
18 serves to illustrate that certain constraints place a permanent cap on the amount of
19 economic optimization that is possible. Sierra Club ignores them completely
20 throughout its testimony.

³⁹ Sierra Club/100, Burgess/20-22.

⁴⁰ Sierra Club/100, Burgess/21

1 **Q. Sierra Club argues that PacifiCorp has no incentive to reduce costs as a result of**
2 **the TAM.⁴¹ How do you respond?**

3 A. Given the persistent under-recovery of NPC previously discussed, this argument has
4 no merit. Not only does PacifiCorp pride itself on providing reliable, least cost
5 energy to our customers, proceedings like this TAM provide an incentive for
6 PacifiCorp to reduce costs as much as possible. The Company operates with
7 foreknowledge that any variances from the TAM forecast will mostly likely be
8 disallowed for recovery because of the PCAM structure and that disallowances for
9 imprudent actions are a real possibility. Additionally, the Company understands that
10 the oversight provided by the Commission has been and will continue to be rigorous.
11 As Mr. Ralston notes in his testimony on the subject, customers have many
12 alternative energy options and can avoid or reduce power purchases from PacifiCorp
13 if rates are not competitive. Finally, Sierra Club argues that the PCAM's sharing
14 band does not incentivize the Company from efficient operations because savings are
15 passed on the customers. The Company disagrees that such a disincentive exists, but
16 to the extent it does, adopting the Company's proposal in its rate case to eliminate
17 those sharing bands would apparently resolve Sierra Club's concern.

18 **Q. Sierra Club also implies that the Commission needs to exercise greater scrutiny**
19 **over coal plant operations. Do you agree?**

20 A. No. As described in more detail in Mr. Ralston's testimony, the Commission has
21 conducted thorough examinations of many different aspects of the Company's coal
22 operations, including its contracting process, long-term fuel plans, dispatch decision-

⁴¹ Sierra Club/100, Burgess/19.

1 making, and participation in the EIM. Any suggestion that the Commission has been
2 lax in its oversight should be rejected.

3 *3. Minimum Burn Requirements*

4 **Q. Sierra Club also criticizes the Company for requiring that plants subject to**
5 **minimum-take provisions consume at least the minimum volume in the NPC**
6 **forecast that accompanies the TAM.⁴² Please explain why the Company includes**
7 **minimum burn requirements.**

8 A. As discussed earlier in my testimony, the Company accounts for minimum-take
9 provisions by using an iterative process to arrive at an incremental fuel price that
10 ensures the plants burn at least the volume required to be purchased under the
11 minimum-take provision of the applicable coal supply agreements. GRID cannot
12 accommodate a contractual minimum-take provision, so this is the mechanism
13 employed to ensure those contractual provisions are respected. The fact that Sierra
14 Club was apparently unaware of this also explains its objection to the fact that the
15 incremental prices in GRID do not uniformly match the incremental prices provided
16 by the Fuels group. The approach taken in GRID correctly recognizes that minimum-
17 take provisions impose costs that the Company incurs regardless of whether the
18 minimum volumes are burned. As a previously incurred cost that cannot be avoided,
19 it makes economic sense to ensure that at least these volumes are burned because they
20 have an effective incremental price of zero.

⁴² Sierra Club/100, Burgess/58.

1 **Q. Sierra Club also argues that there are instances where the supplemental fuel**
2 **prices are used as the incremental fuel cost, driving dispatch decisions. Is this a**
3 **reasonable objection?**

4 A. No. Supplemental coal *is* the incremental fuel price, if there is a minimum-take tier
5 that forms the base of the fuel supply arrangements. As discussed above, costs for a
6 minimum-take contract tier are previously incurred costs, which have an incremental
7 price of zero, meaning that it would be imprudent not to consume at least those
8 amounts.

9 4. *Treatment of Fuel Costs When Calculating NPC*

10 **Q. Please summarize what cost items have been included in coal fuel expense in the**
11 **TAM.**

12 A. Fuel expense includes the invoiced price of fuel, freight/demurrage, excise taxes,
13 operating, maintenance, depreciation, ad valorem taxes, and other expenses directly
14 assignable to cost of fuel as defined by the Federal Energy Regulatory Commission
15 (FERC).

16 **Q. Do you agree with Sierra Club’s recommendation that fixed costs be excluded**
17 **from recovery through the TAM and instead recovered through a general rate**
18 **case?**⁴³

19 A. No. I agree with Sierra Club that NPC includes the forecasted “fuel expenses,
20 wholesale purchase power expenses and wheeling expenses, less wholesale sales
21 revenue.”⁴⁴ However, that definition is not limited to variable costs. Moreover, the

⁴³ Sierra Club/100, Burgess/75.

⁴⁴ Sierra Club/100, Burgess/12.

1 specific FERC accounts that are expressly included in the TAM include fixed fuel
2 costs.

3 **Q. Why does PacifiCorp include the fixed components of variable fuel costs in**
4 **NPC?**

5 A. Those fixed components are included because they are a real and necessary cost of
6 serving load in the Company's service territory, and they are incurred based on
7 contract provisions that are prudent and consistent with industry standards. Elective
8 variability is not a prerequisite to recovery. Using the same logic that was relied upon
9 by Sierra Club, a fixed-price power supply agreement with a wind plant could be
10 similarly excluded from NPC and disallowed.

11 **Q. Sierra Club also claims that PacifiCorp has understated its variable O&M as an**
12 **input to GRID. Is this true?**

13 A. No. The variable O&M costs used in GRID are accurate and have not been
14 artificially lowered to increase plant dispatch as Sierra Club implies. Mr. Schwartz
15 also rebuts Sierra Club's argument on this issue.

16 5. *Response to Sierra Club's Recommendations for 2021 TAM*

17 **Q. Sierra Club recommends an adjustment to the 2021 TAM that would replace the**
18 **fuel costs for the Jim Bridger, Hunter, Craig, and Huntington plants on the**
19 **theory that those plants are not economic and are not subject to minimum take**
20 **requirements for 2021.⁴⁵ How do you respond?**

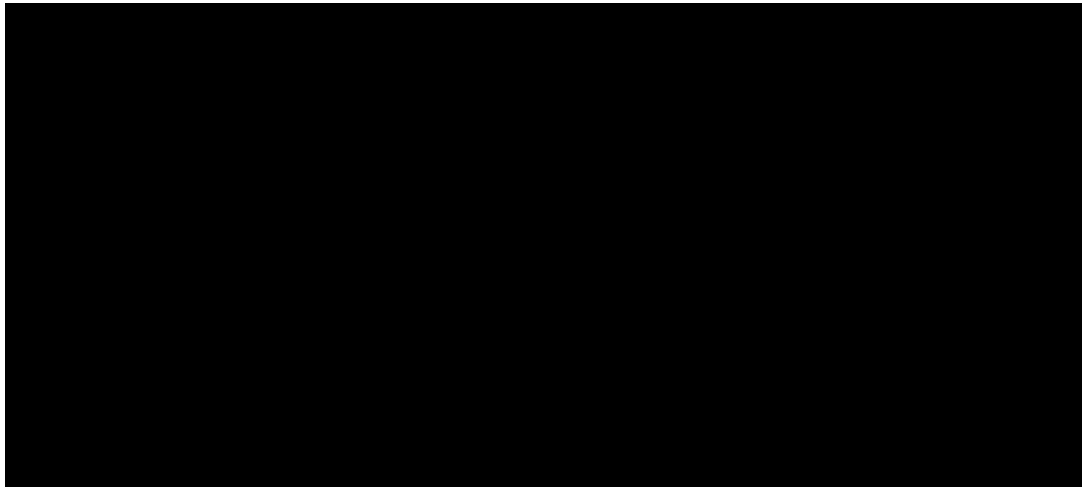
21 A. As explained by Mr. Ralston, Sierra Club's understanding of the coal supply
22 agreements for those plants is incorrect and therefore the adjustment is without merit.

⁴⁵ Sierra Club/100, Burgess/72-73. Sierra Club also include a small adjustment for the Hayden plant related to coal volumes above the contract minimums.

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1 Sierra Club also justifies this adjustment by improperly relying on the average, not
2 incremental price, which is discussed above. Moreover, Sierra Club recommends
3 replacing the fuel costs with the projected fuel costs of the Company's natural gas
4 plants. Sierra Club provides no basis for this substitution. However, the clear
5 implication is that they believe that the Company could and should replace the output
6 from that subset of coal plants with natural gas generation.

7 To demonstrate that these plants are dispatching economically, the Company
8 executed a GRID study removing those plants from the system and allowing their
9 output to be replaced by other available resources. Please note that this study
10 includes no minimum take or liquidated damages impacts. In addition, the screening
11 for every natural gas plant was removed in order to allow GRID the greatest amount
12 of flexibility to determine an economically and operationally feasible generation
13 forecast. The results are presented in Confidential Figure 9 below.



14
15 As evidenced by the bottom line number, PacifiCorp's NPC is much higher without
16 these four plants than with them, undermining Sierra Club's claim that they are
17 uneconomic and could be replaced with cheaper resources. Not evident in the table is

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1 the fact that, upon closer inspection of the market purchases, \$104 million of the
2 \$490 million increase in purchased power expense was attributable to emergency
3 purchases, which is a strong indication that the system cannot remain physically
4 reliable without dispatch from the plants in question. These results also do not
5 consider any potential impact on prices or market liquidity if the Company were to
6 increase its purchases by [REDACTED], so there is a high likelihood that the
7 actual results would be worse than forecast if this were attempted in actual operations.

8 **Q. Sierra Club also recommends removal of fixed fuel costs related to the Black**
9 **Butte and Colstrip contracts included in the 2021 TAM.⁴⁶ How do you respond?**

10 A. As noted above, the TAM is designed to allow PacifiCorp to recover its prudent NPC,
11 a component of which is fixed fuel costs. There is no justification for removing such
12 costs from the TAM, absent a demonstration of imprudence. Neither Sierra Club nor
13 any other party has challenged the prudence of the Black Butte or Colstrip contracts
14 in this case, so Sierra Club's adjustment should be summarily rejected.

15 6. *Response to Sierra Club's Recommendation for Future TAMs*

16 **Q. Does Sierra Club provide any recommendations for future changes to NPC**
17 **modeling in the TAM?**

18 A. Yes. Sierra Club recommends that PacifiCorp update its modeling approach for
19 estimating future NPC as follows:

- 20 • Dispatch coal units based on the average, rather than incremental, price;
21 • Remove the "must run" setting from GRID; and
22 • Remove all "minimum burn" constraints.⁴⁷

⁴⁶ Sierra Club/100, Burgess/75.

⁴⁷ Sierra Club/100, Burgess/80.

1 **Q. How do you respond to these recommendations?**

2 A. Each recommendation should be rejected for the reasons outlined above and in the
3 testimony of Mr. Ralston and Mr. Schwartz. Dispatching using average cost
4 increases NPC and fails to account for actual operations and coal costs that cannot be
5 avoided. Removing the “must run” setting from GRID is addressed in the reply to
6 Staff’s recommendations. And removing the “minimum burn” constraints ignores the
7 reality of coal supply agreements and the fact that the cost of minimum take
8 provisions cannot be avoided and therefore should be modeled in GRID.

9 **Q. Does Sierra Club offer any other recommendations?**

10 A. Yes. Sierra Club recommends that PacifiCorp include for review in the IRP process
11 any new, modified, or updated coal supply agreements with minimum tonnage
12 requirements if PacifiCorp intends to seek cost recovery from Oregon ratepayers.⁴⁸
13 The Company disagrees with this recommendation. As outlined in Mr. Ralston’s
14 testimony, the Commission has already established a process to review fueling
15 strategies for the Company’s coal plants. Moreover, adding these issues into the IRP
16 would change the nature of the IRP from a prospective planning process to a
17 retrospective prudence review.

⁴⁸ Sierra Club/100, Burgess/83.

V. DAY-AHEAD AND REAL-TIME SYSTEM BALANCING TRANSACTIONS

A. Overview and History of the DA/RT Adjustment

Q. Please describe the DA/RT adjustment that the Commission approved in the 2016, 2017, and 2018 TAMs and that PacifiCorp has subsequently included in the 2019 and 2020 TAMs.

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 2016 TAM, Staff, CUB, and ICNU (the predecessor to AWEC) objected to the DA/RT adjustment. The Commission, however, rejected their arguments and approved the adjustment after concluding that it more accurately reflected the costs of system balancing transactions in the Company's NPC forecast.⁴⁹

In the 2017 TAM, Staff, CUB, and ICNU again objected. The Commission again affirmed the DA/RT adjustment, concluding that it "reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs."⁵⁰

In the 2018 TAM, Staff, CUB, and AWEC again objected to the DA/RT adjustment. The Commission again affirmed the adjustment but adopted a modification to use only post-EIM years.⁵¹

⁴⁹ *In the Matter of PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015).

⁵⁰ *In the Matter of PacifiCorp d/b/a Pacific Power's 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016).

⁵¹ Order No. 17-444 at 5-9.

1 In the 2019 TAM no party opposed the DA/RT adjustment.

2 In the 2020 TAM, Staff again objected to the DA/RT adjustment and the
3 Company responded to Staff's adjustment in reply testimony. The case was then
4 settled and the stipulation included no modifications to the DA/RT adjustment.

5 **Q. Please describe how system balancing transactions are included in GRID.**

6 A. System balancing transactions are required to balance the hourly load and resources
7 in the GRID model for the TAM test period. The GRID model calculates the least-
8 cost solution to balance the Company's load and resources each hour. The model
9 makes purchases in the wholesale market (labeled as "system balancing purchases" in
10 the NPC report) in the hours for which the Company does not have enough
11 economically committed owned or contracted resources to meet its load. The model
12 also makes wholesale market sales (labeled as "system balancing sales" in the NPC
13 report) when it has excess resource availability for a given hour, and those resources
14 can have their output economically increased while respecting reliability constraints.

15 **Q. Please describe the price component of the DA/RT adjustment.**

16 A. To better reflect the market prices available to the Company when it transacts in the
17 real-time market, PacifiCorp includes in GRID separate prices for forecasted system
18 balancing sales and purchases. These prices account for the historical price
19 differences between the Company's purchases and sales compared to the monthly
20 average market prices.

21 **Q. Why is the DA/RT adjustment needed to differentiate the market prices for**
22 **purchases and sales?**

23 A. Before the 2016 TAM, the GRID model used an hourly price curve developed from

1 monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) forward market
2 prices. Hourly prices were simply the product of applying a scalar, or shape, to the
3 monthly average prices. These scalars were identical within a given month for each
4 weekday of that month. In addition, the prices were input into the model and did not
5 change regardless of the volume of the system balancing transactions or other system
6 conditions in the model. In reality, however, prices vary within each month and the
7 Company has historically bought more during higher-than-average price periods and
8 sold more during lower-than-average price periods. As a result, the average cost of
9 the Company's daily and hourly short-term firm purchases has been consistently
10 higher than the average actual monthly market price, while the average revenues from
11 its daily and hourly short-term firm sales has been consistently lower than the average
12 actual monthly market price.

13 **Q. Please describe the volume component of the DA/RT adjustment.**

14 A. The Company reflects additional volumes to account for the use of monthly, daily,
15 and hourly products. In actual operations, the Company continually balances its
16 market position—first with monthly products, then with daily products, and finally
17 with hourly products. The products used to balance the Company's forward position
18 in the wholesale market are available in flat 25 MW blocks. The Company's load and
19 resource balance, however, varies continuously each hour in quantities that may vary
20 widely from a flat 25 MW block. Thus, in real world operations, the Company must
21 continuously purchase or sell additional volumes to keep the system in balance.

22 In contrast, GRID has perfect foresight and can model wholesale market
23 transactions at whatever volume is necessary to balance the system. Because of

1 GRID's perfect foresight, it can balance the system with far fewer transactions. The
2 DA/RT adjustment adds additional volumes to NPC to more accurately model the
3 transactions necessary to balance the Company's system.

4 **Q. Did parties again scrutinize the DA/RT adjustment in this case?**

5 A. Yes. Staff's testimony notes that the DA/RT adjustment is "highly complex," and
6 that "Staff spent a significant amount of time looking into the mechanics of the DA-
7 RT volume and price calculations."⁵² Staff also "investigated the Company's choice
8 of market hubs to which the DA-RT adder is applied, the knock-on effect of the DA-
9 RT adder on other wholesale transactions and other system balancing transactions, the
10 Company's historic transactions, and the effects of the Company's EIM participation
11 on DA-RT trading processes."⁵³

12 **Q. Did Staff propose an adjustment?**

13 A. No. After its extensive review, Staff does not have an adjustment to the DA/RT
14 adjustment in this case. But Staff notes that the Company anticipates using the
15 AURORA model to forecast NPC beginning with the 2022 TAM and therefore
16 recommends that the Commission require PacifiCorp to hold a workshop by April 1,
17 2021, to "determine how and whether the DA-RT adjustment is appropriate once
18 AURORA is used to forecast power costs."⁵⁴

19 **Q. Does the Company object to Staff's recommendation?**

20 A. No. The Company agrees to hold the workshop Staff recommends. The Company
21 notes, however, that it is still unclear if the AURORA model could be set in a way

⁵² Staff/200, Enright/50-51.

⁵³ Staff/200, Enright/51.

⁵⁴ Staff/200, Enright/51.

1 that would eliminate the need for the DA/RT adjustment, as Staff suggests. But the
2 Company is willing to explore these issues with the parties through a collaborative
3 workshop to hopefully resolve the continued litigation over the DA/RT adjustment.

4 **Q. Does CUB object to the DA/RT adjustment?**

5 A. No.

6 **B. AWEC's Adjustments on the DA/RT**

7 **Q. Does AWEC object to the DA/RT adjustment?**

8 A. Yes. AWEC is the only party to the 2021 TAM that objects to the adjustment and
9 recommends a reduction of \$8.2 million to the Company's forecasted NPC. Although
10 AWEC characterizes its proposal as a downward adjustment to the DA/RT, in fact, it
11 represents a wholesale change to the Company's OFPC. AWEC's adjustment also
12 has several calculation errors.

13 **Q. Please explain how the Company establishes its OFPC used to determine NPC in**
14 **the TAM.**

15 A. PacifiCorp's natural gas and electricity OFPC are developed from a combination of
16 forward market prices on a given quote date and a long-term fundamentals-based
17 price forecast. The first 36 months of the curve are based upon an average of
18 monthly broker quotes for the market period. Months 37 through 48 are an average
19 of the previous year market forward price and the next year's fundamentals price
20 forecast. A fundamentals-based price forecast is used exclusively beyond month 48.
21 Given that the TAM forecasts NPC for the next calendar year (2021 in this case), the
22 relevant period of the OFPC is based on actual prices market participants are paying
23 today for delivery during 2021.

1 **Q. Please describe AWEC's recommendation regarding forward market prices.**

2 A. AWEC recommends an adjustment to reduce both the natural gas and electric market
3 prices included in GRID to account for alleged historical forecast error.

4 **Q. How do you respond to AWEC's recommendations?**

5 A. AWEC's recommendation is analytically flawed and undermined by AWEC's own
6 prior testimony.

7 **Q. Please explain the analysis used by AWEC to justify its proposed downward**
8 **adjustment to the Company's OFPC.**

9 A. AWEC reviewed the Company's previously issued OFPCs for both natural gas and
10 electric markets and compared the forward price included in the OFPC to the ultimate
11 spot price for the given prompt month. Based on this simplistic and flawed
12 comparison, AWEC claims that PacifiCorp's projected forward prices are excessive
13 and biased.⁵⁵ AWEC purports to quantify the historical difference between forward
14 and spot prices and then applies the historical difference as a percentage reduction to
15 forward prices used in the DA/RT adjustment.⁵⁶

16 **Q. Is there any validity to AWEC's claim that the Company's OFPC systematically**
17 **overstates forward market prices?**

18 A. No. It is not reasonable to evaluate a forecast error for OFPCs in the way described
19 by AWEC. The Company's OFPC used in the TAM is developed from market
20 forwards.⁵⁷ Forecast error is a measure of the difference between forecasted (not
21 *forward*) spot prices and actual spot prices. Comparing forward prices to actual spot

⁵⁵ AWEC/100, Mullins/13.

⁵⁶ AWEC/100, Mullins/14.

⁵⁷ The longer-term OFPC is a fundamentals-based forecast as a proxy for forward prices beyond the period in which observed market forwards are not available.

1 prices is a misapplication of forecast error, because market forwards, which are used
2 in the first 36 months of the OFPC, are observed, and not forecasted. Forward prices
3 represent transaction prices occurring at the time for a future delivery date. It
4 represents a commodities' expected valued at a specified future time and place. Spot
5 price is the price that the energy is bought or sold for immediate payment and
6 delivery. The spot prices tend to be extremely volatile and fairly unknown since they
7 are very specific to both time and place. When comparing spot prices and future
8 contract prices, the difference is usually significant. The most common relationship
9 between spot prices and futures prices, referred to as a normal market, is one where
10 futures contract prices are increasingly higher over time as compared to the current
11 spot price. The higher futures prices reflect carrying costs such as storage, the
12 additional risk posed by the uncertainty of future supply and demand conditions in the
13 marketplace, and the fact that prices for goods generally tend to increase over time. It
14 is impossible for a commodity spot price to be equal to its expected value in the
15 future, unless there is a risk-free market.

16 Market participants cannot transact on a spot price forecast. A spot price
17 forecast merely represents a potential view of what prices will be at some point in the
18 future. Market forwards reflect pricing for contracts that reflect the price, on a given
19 quote date, at which buyers and sellers are transacting for future delivery.

20 Also it is not reasonable to use the price difference between the forward
21 market prices and the spot market prices to adjust forward prices forecast. The
22 market price quotation on a specific trading day from energy brokers, exchanges,
23 direct communication with market participants, and actual transactions executed by

1 the Company reflects the current condition of the market, weather, load, and resource
2 availability. The forecast differences from the historical prices cannot be carried over
3 to the future prices due to the continually changing dynamic of the power market. To
4 ensure the reasonableness of the forward prices, the Company independently gathers
5 third party brokers' quotes for the same forward delivery period and validates to
6 within a specific tolerance range between the broker price averages and forward
7 prices used by the Company.

8 **Q. Is there an expectation that forward prices would equal spot prices, as AWEC's**
9 **testimony suggests?**

10 A. No. It is not strictly true that forward prices will or should equal the expected price.
11 Forward buyers and sellers are considering the trade-off between using a fixed
12 forward price to reduce price volatility and waiting to transact at a risky spot price.
13 To avoid arbitrage, these two prices would have to be equal in present value, not in
14 delivery-date value. In general, it is likely that spot prices are somewhat
15 systematically risky because demand for most commodities tends to move with the
16 economy as a whole. It is therefore unlikely that the appropriate discount rate for
17 taking the present value of expected spot prices will be the risk-free rate that applies
18 to discounting the forward price. For the two present values to be equal, the future
19 values have to be somewhat different.

1 **Q. Has AWEC recommended a similar adjustment to the OFPC in an earlier**
2 **TAM?**

3 A. Yes. In the 2019 TAM, AWEC recommended a similar adjustment based on the
4 same flawed reasoning. That case was ultimately settled, however, with no
5 adjustment to the OFPC.

6 **Q. Is AWEC's position here consistent with its prior testimony regarding the**
7 **DA/RT adjustment?**

8 A. No. In the 2016 TAM, the Industrial Customers of Northwest Utilities' (ICNU) (now
9 known as AWEC) witness Mr. Mullins testified that the Commission should reject
10 the DA/RT adjustment because the adjustment assumed that there was a systematic
11 bias between the OFPC and actual spot market prices. ICNU testified that, "[f]or
12 purposes of power cost forecasting, it is generally accepted that there is no systematic
13 bias between forward market prices and spot market prices."⁵⁸ ICNU explained:

14 This concept is central to power cost forecasting, which is nothing
15 more than a calculation of system dispatch based upon current
16 forward market prices for gas and electricity. One of the reasons
17 why a power forecast based on forward prices can be used in
18 ratemaking, rather than being pure speculation on the part of the
19 utility, is because there is an expectation that the forward prices used
20 in the calculation are an unbiased predictor of future spot prices.⁵⁹

21 So in this case, Mr. Mullins testifies that there is a systematic bias between forward

⁵⁸ Docket No. UE 296, ICNU/100, Mullins/10 ("For purposes of power cost forecasting, it is generally accepted that there is no systematic bias between forward market prices and spot market prices. Accordingly, the market prices at which a utility will transact in forward markets to balance its systems represent the median expectation of what the ultimate spot market prices will be. The notion that forward prices are an unbiased estimate for future spot prices, however, does not mean that the future spot market price will ultimately be equal to what the forward market predicts. Rather, the price at which a utility may enter into a transaction in forward markets is expected to be higher than spot prices 50% of the time, and less than spot prices the other 50% of the time. Thus, to the extent that a utility is ultimately required to transact for more or less power in hourly spot markets than previously sold or purchased in forward markets, it is expected to be no better or worse off than if it had solely purchased its power requirements in spot markets.")

⁵⁹ Docket No. UE 296, ICNU/100, Mullins/10.

1 and spot market prices, while in the 2016 TAM, Mr. Mullins testified such a bias
2 would undermine the “central” concept of power cost forecasting.

3 **Q. Did AWEC’s testimony subsequently change in the 2018 TAM?**

4 A. Yes. After the Commission rejected Mr. Mullins’ recommendations in the 2016
5 TAM, he opposed the DA/RT adjustment again but used an entirely opposite
6 rationale. In the 2018 TAM, ICNU testified that transactions entered more than seven
7 days before the settlement period (i.e., hedging transactions) systematically generate
8 customer benefits because the forward price curve is systematically lower than actual
9 spot market prices.⁶⁰ In this case, AWEC’s adjustment is premised on the opposite—
10 AWEC claims that the forward price curve is systematically higher than actual spot
11 market prices.

12 Taken together, AWEC has opposed the DA/RT adjustment because (1) there
13 is no bias between the forward price curve and actual spot market prices (2016
14 TAM), (2) the forward price curve is systematically *lower* than actual spot market
15 prices (2018 TAM), and (3) the forward price curve is systematically *higher* than
16 actual spot market prices (2021 TAM). In other words, according to Mr. Mullins, the
17 DA/RT adjustment should be eliminated or modified because the forward price curve
18 is too high, too low, and just right. Such contradictory and opportunistic positions
19 undercut the credibility of AWEC’s analysis.

⁶⁰ See *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, ICNU/200, Mullins/9 (Aug. 2, 2017) (arguing DA/RT must include transactions more than seven days ahead because “Whether the offsetting benefits relate to the hedging components, or some other factor, is an irrelevant consideration. If there is an offsetting systematic benefit associated with these longer-term contracts, those benefits are appropriately applied against the impact of the DA/RT, irrespective of what is causing the benefit. In addition, it is important to consider that the transactions in question are not financial transactions, such as swaps or options, but are 14 physical transactions resulting in the delivery of actual power.”)

1 **Q. How does AWEC tie the supposed bias in the OFPC to the DA/RT adjustment?**

2 A. AWEC points out that the DA/RT adjustment is calculated using the difference
3 between actual historical monthly prices and actual historical day-ahead and real-time
4 prices. That historical difference based on actual prices is then applied to forward⁶¹
5 prices, which AWEC claims creates an apples-to-oranges comparison between
6 forward and spot prices.⁶²

7 **Q. Is there any validity to AWEC's argument?**

8 A. No. The DA/RT adjustment has always used the historical difference between actual
9 prices to adjust the forward prices used in the TAM and there is nothing unreasonable
10 about continuing to use that approach in this case. Similarly, the usage of the
11 California Independent System Operator (CAISO) actual day-ahead prices for the
12 OFPC hourly scalars relies on the comparable information.

13 AWEC's adjustment is self-contradicting. AWEC applied a downward
14 adjustment to the electric market prices used in the DA/RT adjustment to account for
15 the forward market price over-estimation. The GRID model uses forward market
16 prices, in order to make the DA/RT adjustment consistent with what used in GRID
17 model, following AWEC's logic, an upward adjustment should be proposed to the
18 power market prices used in DA/RT.

19 **Q. Does AWEC's adjustment also fundamentally change the purpose of the DA/RT**
20 **adjustment?**

21 A. Yes. As discussed above, the DA/RT adjustment models a systematic difference

⁶¹ AWEC at times describes the OFPC has having "forecasted" prices, which is not an accurate term. The correct term is forward.

⁶² AWEC/100, Mullins/14.

1 between the average market price and the average purchase and sales price. AWEC's
2 adjustment to the OFPC, however, measures the difference between the forward price
3 curve and the point in time when the energy is delivered. In this way, AWEC's
4 adjustment measures something completely different from the DA/RT adjustment.

5 Moreover, in the 2016 TAM, ICNU argued that the historical difference
6 between forward and spot prices are indicative of the changing market conditions in
7 the historical period and "will not correspond to the market conditions" in the test
8 period.⁶³

9 **Q. Do you have any additional response to AWEC's testimony?**

10 A. Yes. AWEC's fundamental argument is that the OFPC is biased. Such a claim has
11 far reaching consequences because the Company uses the OFPC for many different
12 purposes, including setting avoided cost prices and long-term resource planning.
13 AWEC is essentially proposing a wholesale shift from using *forward* prices, which
14 are observable and not forecast, to a wholly *forecast* price curve. Even if the
15 Commission were inclined to explore such a foundational change and abandon the
16 use of *forward* prices, AWEC's analysis is overly simplistic and provides no basis as
17 a methodology for forecasting future spot market prices.

18 **Q. Do you have any other concerns about AWEC's adjustment?**

19 A. Yes. First, AWEC had several calculation errors in its adjustment. Instead of
20 applying the downward adjustment to the power market prices used in the DA/RT, it
21 was incorrectly applied to the volume component of DA/RT, the energy change in
22 volume component of DA/RT and the number of hours in each month. Second, the

⁶³ Docket No. UE 296, ICNU/100, Mullins/15-16.

1 proposed adjustment to natural gas prices was simply done by reducing the natural
2 gas fuel expense for a certain percentage instead of adjusting the prices used in
3 GRID. By doing this, it completely ignores the system dispatch in GRID and the
4 impact of natural gas prices on the thermal generation volume.

5 **Q. Does AWEC recommend any other modifications to the DA/RT adjustment?**

6 A. Yes. AWEC also recommends that the impact of the Enbridge outage be removed
7 from historical data set used to calculate the DA/RT adjustment because it was not a
8 normal event and should be removed from a normalized forecast.⁶⁴

9 **Q. Do you agree that the impact of the Enbridge outage should be removed?**

10 A. No. The use of a historical average to calculate the DA/RT adjustment effectively
11 normalizes the result even when events like the Enbridge outage are included in the
12 historical data set.

13 **Q. Has the Commission previously addressed whether anomalous events like the**
14 **Enbridge outage should be removed from the DA/RT adjustment?**

15 A. Yes. In the 2016 TAM, ICNU and CUB argued that the anomalous weather events
16 improperly increased the DA/RT adjustment and resulted in a non-normalized
17 adjustment.⁶⁵ The Commission rejected this argument and concluded that the “use of
18 three years of data is sufficient to smooth out variations to generate a reasonable
19 estimate of expected spot price differentials.”⁶⁶ The current DA/RT adjustment is

⁶⁴ AWEC/100, Mullins/14.

⁶⁵ Docket No. UE 296, ICNU/100, Mullins/18 (“**Q. Have recent weather anomalies impacted the Company’s calculations?** A. Yes. In fact, based upon my review of the Company’s calculations, the reason that the spreads were so high in February 2014 is due to the fact that power prices at Mid-Columbia exceeded \$280/MWh in certain hours as a result of extraordinary weather and market conditions in the Northwest in the first half of that month. Reliance upon these conditions produces an unreasonable result, as the impact of historical weather events should be normalized out of power costs.”); Order No. 15-394 at 3.

⁶⁶ Order No. 15-394 at 4

1 based on four years of historical data and therefore produces a normalized result
2 without having to exclude events such as the Enbridge outage.

3 **Q. AWEC also recommends that the DA/RT adjustment be calculated over a longer**
4 **period of time.⁶⁷ Is that a reasonable recommendation?**

5 A. No. The Company uses 48 months of historical data as the base for the historical
6 DA/RT adder calculation. In accordance with Commission Order No.17-444, the
7 Company is required to use data from years following participation in the EIM. The
8 48-month historical data as of June 2019 was the best data available at the time of the
9 2021 TAM initial filing. The 48-month normalization period is consistent with most
10 of the GRID data input assumptions and sufficient to normalize any extreme events in
11 the past history.

12 **Q. Are there any other reasons that AWEC's proposed DA/RT adjustment is**
13 **unreasonable?**

14 A. Yes. As discussed above, the Company's NPC forecast is consistently lower than
15 actuals, even with the DA/RT adjustment capturing system balancing costs that are
16 not reflected in GRID. Given this persistent under-recovery, it is unreasonable to
17 further decrease the NPC forecast as AWEC recommends.

18 **VI. OTHER MODELING ADJUSTMENTS**

19 **A. Modeling QF contracts**

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

21 A. The forecast for QF costs in the TAM is based on QF contracts with specific prices
22 and terms. The contract may specify an exact quantity of capacity and energy or a

⁶⁷ AWEC/100, Mullins/14.

1 range bounded by a maximum and minimum amount, or it may be based on the actual
2 operation of a specific facility. Prices may also be specifically stated, may refer to a
3 rate schedule or a market index, or may be based on some type of formula. Every QF
4 contract is modeled individually. For QF contracts with a nameplate capacity greater
5 than 10 MW, the delivery energy forecast is based on 48-month normalization
6 assumptions. For QF contracts with a nameplate less than or equal to 10 MW, the
7 delivery energy forecast uses the actual delivery schedule available before the filing.
8 For renewable QFs with a nameplate greater than 10 MW, the forecasted capacity
9 factor is based on either full history if the QF has been online longer than four years,
10 or based on P50 if the QF has been online shorter than four years.

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

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

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

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

22 A. Staff proposes to reduce QF contract costs in this case by approximately four percent

REDACTEDPAC/500
Webb/70

1 to account for past over-forecasts of total QF costs.⁶⁸ The adjustment reduces NPC
2 by approximately [REDACTED].

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

4 A. Staff compared actual QF costs to forecasted QF costs from 2017, 2018, and 2019
5 and concluded that PacifiCorp "consistently overestimates its QF purchase power
6 costs."⁶⁹ Staff then concludes that because "PacifiCorp has not identified in
7 testimony any change in approach for estimating QF power costs, there is no reason
8 to assume that the consistent overestimation has been rectified[.]"⁷⁰ Staff's
9 adjustment reduces the QF forecast by the average difference between forecasted and
10 actual QF costs from 2017, 2018, and 2019.

11 **Q. Do you agree with Staff's characterization that PacifiCorp has not changed its**
12 **methodology for estimating QF power costs?**

13 A. No. Staff ignores the methodology change that was implemented for the 2018 TAM.
14 Although the CDR is not new to the 2021 TAM, the historical data set Staff uses
15 includes pre-CDR data from 2017. So, Staff's claim there has been no change to how
16 PacifiCorp forecasts QF costs ignores the fact that there was a change after 2017 and
17 therefore relying on 2017 data is problematic. Indeed, reviewing Staff's own analysis
18 shows that calculating its adjustment using only data that includes the CDR reduces
19 Staff's proposed adjustment by nearly 25 percent.

⁶⁸ Staff/400, Zarate/10.

⁶⁹ Staff/400, Zarate/10.

⁷⁰ Staff/400, Zarate/10.

1 **Q. In addition to Staff’s reliance on pre-CDR data, does PacifiCorp have any other**
2 **objections to Staff’s adjustment?**

3 A. Yes. Staff’s adjustment cherry-picks a single NPC line-item that is over-forecast
4 without regard for the fact that PacifiCorp has under-recovered total NPC throughout
5 2017-2019.

6 **Q. Are there other problems with Staff’s QF adjustment?**

7 A. Yes. Staff’s proposal is one-sided by removing the cost of QF power purchase
8 agreements without removing the energy associated with these QF costs, essentially
9 providing customers with free energy.

10 **B. Load Forecasting**

11 **Q. Staff recommends that the Company incorporate any adjustments or changes to**
12 **the load forecast made in the Company’s concurrent general rate case (docket**
13 **UE 374) into this docket if there is sufficient time to do so.⁷¹ Does the Company**
14 **agree with this proposal?**

15 A. Yes. The Company agrees. Because of the different procedural schedules, however,
16 any adjustments to the load forecast in docket UE 374 will not occur in time to
17 include in the Reply Update addressed above. If and when changes to the load
18 forecast are made in docket UE 374, the Company will incorporate those changes into
19 the NPC modeling in this case.

⁷¹ Staff/100, Gibbens/5.

1 **C. Nodal Pricing Model**

2 **Q. Please describe the Company's proposed transition to a Nodal Pricing Model**
3 **(NPM).**

4 A. As explained in the direct testimony of Company witness Mr. Michael G. Wilding in
5 docket UM 1050,⁷² PacifiCorp is currently working on a new approach to modeling
6 and allocating NPC as one of the Framework Issues in the 2020 Protocol. Beginning
7 in 2024, the Company will use a new system for ratemaking that is referred to as the
8 NPM.

9 **Q. Please describe the NPM.**

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

19 **Q. Please describe conceptually how the NPM will work.**

20 A. The NPC associated with each generating resource will be assigned to states based on
21 each generating resource's assignment. For example, if a state is assigned 25 percent

⁷² See *In the Matter of PacifiCorp Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, PAC/300, Wilding/6-14 (Dec. 3, 2019).

1 of a natural gas plant, then it is also assigned 25 percent of the fuel costs associated
2 with that resource, regardless of load. Each resource also receives a credit based on
3 the locational marginal price (LMP) for its generation, which is also assigned to each
4 state per its assignment of each generating resource. The assigned NPC, less the
5 credit received, will be the states' total NPC.

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

7 A. Each generating resource will receive a credit for the energy it generates or the
8 reserves it provides, and each state's load will be charged a load aggregated point
9 (LAP) price.⁷³ The total credits the generating resources receive will equal the dollar
10 amount that each state's load is charged. This facilitates a transfer of energy between
11 states at a fair price based on the LMP and preserves the benefits of a system dispatch
12 and optimization.

13 **Q. What is the current status of the NPM?**

14 A. CAISO has developed the NPM and beginning in 2021, the NPM will be used to
15 dispatch the Company's resources.

16 **Q. Please describe Staff's proposed adjustment.**

17 A. Staff reasons that the NPM "represents a new dispatch algorithm" and that "this more
18 complex dispatch system . . . will provide cost savings through a more optimal
19 solution to generation dispatch."⁷⁴ Because of this, Staff recommends that the
20 "efficiency gains as a result of the new dispatch logic should be passed onto
21 customers in this year's TAM."⁷⁵

⁷³ The LAP price is the weighted average LMP at each load point or node within the LAP.

⁷⁴ Staff/100, Gibbens/9.

⁷⁵ Staff/100, Gibbens/10.

1 **Q. Did Staff quantify its adjustment?**

2 A. No. Staff neither quantified its adjustment nor provided any proposed methodology
3 for determining such an adjustment. Instead, Staff simply indicates it will work with
4 the Company and intervenors to arrive at a reasonable number but provides no
5 explanation for how this will occur.

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

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

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

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

17 **Q. How do actual operations depart from GRID?**

18 A. In actual operations, the Company's dispatch is not perfectly optimized (with the
19 exception of the EIM). This means that human operators are making dispatch
20 decisions based on the best available information. That information, however, is
21 inherently imperfect and a human operator is therefore making dispatch decisions
22 without perfect foresight into system conditions, which are constantly changing.
23 While the Company will experience benefits from the NPM in its actual operations,

1 those benefits will only bring actual costs closer to the ideal dispatch calculated in the
2 GRID model. Therefore, PacifiCorp's modeled NPC already incorporates dispatch
3 savings compared to the Company's actual operations. Imputing incremental NPM
4 dispatch benefits outside of GRID is therefore unreasonable.

5 **Q. Staff analogizes the NPM to PacifiCorp's participation in the EIM.⁷⁶ How do**
6 **you respond to that analogy?**

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

12 **Q. Please describe the intra-regional EIM benefits.**

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

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

20 A. Yes. In the 2017 TAM (docket UE 307), Staff and CUB recommended an adjustment
21 to impute intra-regional EIM benefits.⁷⁷ In that case, the Company explained that
22 because GRID is already perfectly optimized, in every hour the lowest cost resources

⁷⁶ Staff/100, Gibbens/10.

⁷⁷ Order No. 16-482 at 15.

1 will be dispatched, subject to transmission constraints, and the intra-regional benefits
2 manifest as a decrease in the Company's actual, not modeled, NPC.⁷⁸ Thus,
3 PacifiCorp testified that the intra-regional benefits are real, but they are already built
4 into the Company's overall NPC forecast. In other words, the more efficient dispatch
5 that has always been reflected in the GRID model could now be achieved in actual
6 operations.

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

8 A. The Commission rejected the imputation of intra-regional benefits after concluding
9 that the "GRID forecast already accounts for intra-regional benefits because the
10 model optimizes dispatch on an hourly basis."⁷⁹

11 The same is true here. The use of the NPM to more efficiently dispatch
12 resources in actual operations will bring actual costs closer to the ideal dispatch
13 calculated in GRID. Because these benefits are already included in the NPC forecast,
14 the imputation of additional benefits would be double-counting.

15 **D. 2019 IRP Flexible Reserve Study**

16 **Q. Staff recommends that PacifiCorp update the flexible reserve study that was**
17 **included in the 2019 IRP based on the most recent 12 months of data.⁸⁰ How do**
18 **you respond?**

19 A. As mentioned in Mr. Mitchell's reply testimony, the flexible reserve benefit changed
20 from 104 MW to 92 MW based on the most recent information. The Company will

⁷⁸ See Order No. 16-482 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.")

⁷⁹ Order No. 16-482 at 16.

⁸⁰ Staff/200, Enright/45.

1 update NPC when the 2019 flexible reserve study is updated in the IRP.

2 **E. Jim Bridger SCRs**

3 **Q. Both Staff and CUB recommend that the Company adjust its NPC forecast to**
4 **remove the impact of the SCR systems installed on Jim Bridger Units 3 and 4 if**
5 **the Commission finds those investments imprudent in docket UE 374.⁸¹ How do**
6 **you respond?**

7 A. While PacifiCorp will comply with any order on the Jim Bridger SCR systems that is
8 issued by the Commission, PacifiCorp does not feel it is appropriate to adjust the
9 minimum operating levels for Jim Bridger in GRID at this time. PacifiCorp has
10 provided ample evidence of the prudence of the Jim Bridger SCR investments in
11 docket UE 374. Additionally, the minimum operating level for Unit 3 has already
12 been reduced below pre-SCR levels as the warranty on the SCR has expired. The
13 warranty on Unit 4 expires at the end of 2021 and PacifiCorp will make the
14 appropriate adjustments to reflect a lower minimum operating level to reflect this
15 operational reality.

16 **F. Wheeling Revenues**

17 **Q. CUB proposes that the TAM include the wheeling revenues earned by the**
18 **Company through the provision of wholesale transmission service.⁸² Does the**
19 **Company agree with this recommendation?**

20 A. No.

⁸¹ Staff/400, Zarate/3-4; CUB/100, Jenks/43.

⁸² CUB/100, Jenks/4-9.

1 **Q. Please summarize the wheeling revenue proposal by CUB.**

2 A. CUB proposed to remove the wheeling revenue from the Company's pending general
3 rate case, docket UE 374, and include it in the annual TAM filing given that wheeling
4 revenue is a variable component so it should be tracked in the TAM.

5 **Q. Is it appropriate to include wheeling revenues in the TAM?**

6 A. No. Transmission revenues are how the Company recovers transmission costs from
7 third-party users of the Company's transmission system. These revenues are included
8 in base rates to offset the transmission costs in the revenue requirement
9 calculation. This way the net transmission cost is included in base rates. This is
10 consistent with the matching principle, to match the benefits (transmission revenues)
11 and the costs (transmission investments, O&M) in the same filing.

12 **Q. What is wheeling cost and why it is included in the TAM?**

13 A. Wheeling costs are the expenses the Company pays when the Company uses third
14 parties' transmission systems. When the Company needs to move energy to serve
15 load and keep the system balanced, the Company will sometimes need additional
16 transmission capacity to do so. The expense is defined as a variable cost and captured
17 in FERC account 565, which is part of the definition of NPC. The incurrence of this
18 expense ties to the operational need and varies over time. The TAM, as the annual
19 filing to reflect various cost changes over time, includes wheeling costs.

20 **Q. How do you address CUB's concerns about wheeling revenue since it is a**
21 **variable component in the revenue requirement?**

22 A. Oregon's allocation of any differences between actual wheeling revenues and the
23 estimated level included in base rates are captured through a deferral account. The

1 wheeling revenue forecast in docket UE 374 reflects the forecasted rate for 2021
2 based on the formula approved by FERC in ER11-3643.⁸³ The wheeling rate is
3 updated every year based on the approved FERC formula. The distinction between
4 docket UE 374 and the previous two Oregon general rate cases is that the Company
5 was in the midst of the FERC rate case at that time and it was unknown as to what
6 would be approved by FERC and how that would impact wheeling revenues. Going
7 to the formula rate was a change for the Company and with the uncertainty around
8 what would be approved, it was difficult to estimate wheeling revenues for the
9 purposes of a general rate case so the Company agreed to the deferral. In docket UE
10 374, the approved formula has been in place for many years and the Company is
11 using this formula to calculate transmission rates and estimate wheeling revenues.

12 **Q. What other concerns does the Company have regarding this proposal?**

13 A. Wheeling revenue is when third parties purchase transmission rights on PacifiCorp's
14 transmission system and are an offset to the Company's transmission assets not
15 wheeling expenses. Without including the capital investment changes in base rates, it
16 is a mismatch to include the change of wheeling revenue in the TAM. Additionally,
17 wheeling revenues are not associated with the variable cost of serving load.

18 **Q. CUB pointed out that the Company's wheeling revenues are included in the**
19 **annual power cost proceeding in Utah.⁸⁴ How do you respond?**

20 A. CUB failed to explain that the annual energy balancing account (EBA) proceeding in
21 Utah is a 100 percent dollar-for-dollar power cost recovery mechanism. Wheeling

⁸³ *In re PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

⁸⁴ CUB/100, Jenks/5.

1 revenues in NPC along with a dollar-for-dollar recovery in the Utah EBA provide an
2 equal distribution between the Company and customers when sharing prudently
3 incurred costs and revenues in the NPC. The proposal to include wheeling revenues
4 in the TAM would further increase the magnitude of the chronic NPC under-
5 recovery. The differences between actual and forecasted wheeling revenues may not
6 be appropriately recovered since this difference would be subject to the dead band,
7 sharing band and earnings test in the PCAM.

8 **Q. CUB has requested that PacifiCorp make the change to wheeling revenues in the**
9 **TAM guidelines. How do you respond?**

10 A. The Company believes that changes to the TAM guidelines are better addressed in the
11 concurrent general rate case (docket UE 374). It is my understanding that CUB has
12 proposed the same issues in the general rate case as well.

13 **G. Deer Creek Pension Costs**

14 **Q. CUB recommends that legacy pension costs resulting from the closure of the**
15 **Deer Creek mine be removed from the TAM and recovered through base**
16 **rates.⁸⁵ How do you respond?**

17 A. The Company appreciates CUB's recommendation because, according to CUB, it was
18 intended to ensure that the Company is able to recovery the legacy pension costs even
19 after coal expenses are no longer included in Oregon rates. The Company agrees that
20 an adjustment to move legacy pension costs associated with the Deer Creek Mine
21 from the TAM and into base rates is appropriate.

⁸⁵ CUB/100, Jenks/9-12.

1 **H. Natural Gas Optimization Margins**

2 **Q. Please describe AWEC's proposed adjustment ostensibly intended to reflect**
3 **natural gas optimization margins that are not included in GRID.**

4 A. AWEC claims that PacifiCorp has many opportunities to purchase and sell natural gas
5 transportation rights in order to optimize natural gas margins and that these margins
6 are not captured in GRID.⁸⁶ Therefore, AWEC proposed an adjustment that
7 decreases NPC by \$300,000 to reflect the margins AWEC claims the Company earns.

8 **Q. Has this issue been raised in prior TAMs?**

9 A. Yes. In the 2020 TAM, AWEC recommended a comparable adjustment. As part of
10 the settlement in that case, PacifiCorp agreed to host a workshop prior to the 2021
11 TAM to address AWEC's claims.

12 **Q. Did the Company hold the workshop?**

13 A. Yes. The Company gave an overview of natural gas operation activities when serving
14 system load and maintaining a reliable system, and the details on how the Company
15 operates the natural gas units located in each of PacifiCorp' balancing areas. An
16 overview of the hedging policy was discussed in the workshop as well.

17 **Q. Does the Company engage in the type of natural gas optimization activities that**
18 **AWEC claims?**

19 A. No. AWEC incorrectly assumes that the Company buys and sells natural gas
20 transportation rights for the purpose of optimizing margin in the natural gas market.
21 In fact, the Company procures natural gas supply to fuel its plants in order to serve
22 the system load at the lowest possible cost. When hedging natural gas, the Company

⁸⁶ AWEC/100, Mullins/8.

1 does not over-procure the fuel supply beyond what is needed to reliably serve system
2 peak load. The Company does not engage in any kind of speculative trading. Once
3 the system peak load is met, the Company may sell any excess into the market. Any
4 excess natural gas is dependent on system conditions. These conditions can change
5 throughout the day and month. Since the Company does not procure natural gas
6 beyond its requirements, it is impossible to predict if or when the excess supply may
7 be available.

8 **Q. AWEC claims that the Company's responses to AWEC Data Requests 11 and 12**
9 **show that "at times when it is economic to do so, PacifiCorp is reselling gas to**
10 **earn margins, rather than burning it in its power plants."⁸⁷ Is this true?**

11 A. No. AWEC's testimony never explains the basis for this statement and the testimony
12 failed to identify a single transaction that supports this conclusion. Instead, AWEC
13 simply claims that it identified "over \$20,000,000 in opportunistic natural gas sales
14 revenues in 2019[.]"⁸⁸ Without actually explaining which transactions were
15 identified or even explaining how AWEC came to believe the transactions were
16 opportunistic, there is no evidentiary basis for AWEC's claim.

17 In addition, AWEC's proposed adjustment assumes a five percent margin per
18 trade but AWEC's testimony never explains the basis for that assumption. In sum,
19 AWEC's testimony fails to provide sufficient justification to support an adjustment
20 and should be rejected.

⁸⁷ AWEC/100, Mullins/9.

⁸⁸ AWEC/100, Mullins/10.

1 **Q. Why would the Company sell natural gas?**

2 A. The Company procures natural gas supply in the forward market based on anticipated
3 future fueling requirements. At the time of delivery, market conditions may have
4 changed such that the one or more plants is uneconomic to operate based on the spot
5 market spark spread. When that occurs, the Company will purchase power that it
6 would otherwise have generated and sell the natural gas back into the market, as it is
7 no longer required. This purchase of power and sale of fuel is referred to as a reverse
8 toll. It is important to note that the Company may sell the excess natural gas at a
9 premium or loss. For the Company, the goal is to economically optimize its resources
10 in a way that minimizes NPC, not to profitably trade natural gas.

11 **Q. Can you provide an example of how this might play out in actual operations?**

12 A. Yes. Consider the following two examples in Figure 10 which show the NPC impact
13 when the natural gas forward prices and spot prices are different:

14 **FIGURE 10**

Gas Reverse Toll			
	Example 1	Example 2	Units
Forward Gas Volumes Purchased	38,500	38,500	MMBtu
Operating Heat Rate	7.7	7.7	MMBtu/MWh
Expected Generation	5,000	5,000	MWh
Gas Forward Purchase Price	\$2.50	\$3.00	/MMBtu
Spot Gas Price	\$3.00	\$2.50	/MMBtu
Spot Power Price	\$23.00	\$19.00	/MWh
Spot Spark Spread	-\$0.10	-\$0.25	/MWh
NPC with gas generation	\$96,250	\$115,500	
NPC without gas generation	\$95,750	\$114,250	
NPC Reduction	-\$500	-\$1,250	

15 In both examples, the Company has purchased fuel on a forward basis with
16 the expectation that the unit being hedged would generate 5,000 MWh over the
17 course of the day in order to serve load. In Example 1 in Figure 10, the spot market

1 spark spread is $-\$0.10/\text{MWh}$ which is based on the spot natural gas price, the unit's
2 operating heat rate, and the spot power price. However, given that the spot market
3 indicates that the unit in question is uneconomic, the Company would sell the fuel
4 that was purchased ahead of time and instead purchase power in order to offset the
5 lost generation. In the example above, the Company makes money on the natural gas
6 sale, but *is required to also purchase power*. In the end, the NPC impact is just the
7 spot market spark spread of $-\$0.10/\text{MWh}$ multiplied by the volume of 5,000 MWh.

8 **Q. Why does the above approach serve to reduce NPC?**

9 A. The reason this reduces NPC is that, instead of burning 38,500 million British thermal
10 units (MMBtu) at a purchased price of $\$2.50/\text{MMBtu}$, which generates NPC of
11 $\$96,250$, the Company would elect to sell the natural gas at a profit of $\$19,250$
12 $(38,500 \text{ MMBtu times the sale margin of } \$0.50/\text{MMBtu})$, which effectively defrays
13 the purchased power cost of $\$115,000$ (spot power price of $\$23.00/\text{MWh}$ multiplied
14 by expected requirements of 5,000 MWh), for a total NPC of $\$95,750$. This results in
15 a $\$500$ NPC savings (i.e. $95,750 - 96,250 = 500$).

16 **Q. Would this activity still be optimal if the natural gas sale was not profitable on**
17 **its own?**

18 A. Yes. To make this clear, we can show an example where the fuel sale loses money.
19 In Example 2 of Figure 10, the Company purchased natural gas in the forward market
20 at $\$3.00$ per MMBtu, and will sell that fuel back into the market at a prevailing spot
21 price of $\$2.50$ per MMBtu. Despite that loss, selling the fuel is a part of a logical
22 dispatch optimization plan that serves to minimize NPC, and once again the NPC
23 impact is simply the spot spark spread of $-\$0.25/\text{MWh}$ multiplied by the volume of

1 5,000 MWh. The drivers and method of calculation here are identical to how they
2 were described in the first example and the result is \$1,250 of NPC savings.

3 **Q. Does this constitute natural gas optimization?**

4 A. No. The most important thing to realize about this scenario is that this is simply
5 dispatch optimization, which GRID is fully capable of simulating. The Company
6 includes any existing hedges along with the actual dollar value of those hedge
7 volumes as a GRID input so that the model outcome reflects an efficiently optimized
8 result that acknowledges the existing state of the portfolio at the time the study is run.
9 AWEC has mistaken this for natural gas optimization profit when this is simply what
10 dispatch optimization looks like in actual operations. The choice to reverse toll in
11 either of the two above examples generates NPC savings, and this economic decision-
12 making logic is fully captured in GRID, as well as any dollar impact.

13 **Q. What drivers are considered in actual operations when determining if**
14 **generation or reverse tolling is optimal?**

15 A. The Company considers economics as well as reliability in making dispatch
16 optimization decisions in actual operations. In particular, the spot market spark
17 spread is considered along with physical and reliability constraints. In this way,
18 GRID mimics actual operations (or vice versa), which means that an out-of-model
19 adjustment is not necessary to reflect the value of this activity in forecasted NPC.

20 **Q. Are there any exceptions to what you've demonstrated with these examples?**

21 A. Not economically, but there are physical exceptions. I have made the simplifying
22 assumption above of presenting these scenarios as binary choices when they are not
23 in actual operations. There are cases when the Company may choose to operate a unit

1 at reduced output instead of a full reverse toll in order to provide reserves or avoid
2 start charges, even though the spot market spark spread is negative. However, as
3 mentioned above, GRID accounts for that as well, and that should not take away from
4 the fact that the Company procures natural gas on a forward basis, then makes fuel
5 balancing decisions in the spot market based on well-understood economic theories
6 that are practically applied for the purpose of NPC minimization.

7 **Q. What would you conclude about AWEC's proposed natural gas adjustment?**

8 A. Dispatch optimization requires natural gas sales to be executed, and AWEC has
9 presented no evidence that the Company's sales are not a product of this dynamic, or
10 that GRID is not properly recognizing and incorporating these opportunities into the
11 forecast.

12 **I. 300 MW Link Jim Bridger to Walla Walla**

13 **Q. Please describe AWEC's recommendation on this issue.**

14 A. AWEC recommends including a virtual 300 MW transmission link between the Jim
15 Bridger transmission area and Walla Walla transmission area in the GRID model to
16 reflect the potential benefits resulting from increasing participation in the EIM.⁸⁹
17 AWEC estimates that its adjustment decreases NPC by up to \$2.2 million but
18 recommends that the Company re-run GRID with the additional transmission link to
19 update the impact of the adjustment.⁹⁰

20 **Q. Has the Company included this virtual link in prior TAM filings?**

21 A. No. However, as part of the settlement in the 2019 TAM, docket UE 339, the
22 Company included a monetary adjustment for this link in that case on an expressly

⁸⁹ AWEC/100, Mullins/4-5.

⁹⁰ AWEC/100, Mullins/2.

1 non-precedential basis. The Company did not include the virtual transmission link in
2 the 2020 TAM.

3 **Q. What is the basis for AWEC's imputation of this virtual transmission link?**

4 A. AWEC argues that this adjustment is necessary to conform the NPC modeling in the
5 TAM to the modeling used by the Company to evaluate the Energy Vision 2020
6 resources in its 2017 IRP and 2017R Request for Proposals (RFP) analysis.⁹¹

7 **Q. How do you respond to AWEC's adjustment?**

8 A. PacifiCorp disagrees that it is reasonable to impute a virtual transmission link
9 between Jim Bridger and Walla Walla in the TAM because such a link does not exist.

10 **Q. Did the Company include this virtual link in the 2021 TAM?**

11 A. No. The Company did not include this link in the current TAM. The virtual 300 MW
12 transmission link between the Jim Bridger to Walla Walls is not a "firm" transmission
13 path available to the Company after Idaho Power Company (IPC) joined the EIM.
14 The transmission available for EIM use is limited by two factors. First, the
15 transmission path is influenced by the status of a large number of independent
16 components in the EIM market. Second, the availability of this transmission right is
17 heavily dependent on how IPC operates its system. If the PacifiCorp has scheduled
18 forward transactions that use this path, IPC may operate its system by using the path
19 for its own delivery. There is less transfer capacity available to the Company for EIM
20 transactions.

21 The inter-regional EIM benefits include benefits associated with inter-regional
22 dispatch, which result from transactions between EIM participants. When the

⁹¹ AWEC/100, Mullins/3.

1 Company enters the EIM market, as a requirement, the Company submits its balanced
2 base schedule 55 minutes prior to the hour. The Company has no way to know that
3 this 300 MW transmission link is available, and without this information, it is
4 impossible for the Company to schedule energy based on this 300 MW transmission
5 link.

6 Even when the 300 MW transmission link becomes available to the Company
7 in the sub-hourly EIM market, the realized benefits are already captured in the inter-
8 regional EIM benefits in NPC. For example, when the transmission is available, the
9 Company is able to move zero-fuel cost wind energy from constrained areas of
10 Wyoming to serve load of other EIM participants. This benefit is captured in an out-
11 of-model adjustment.

12 **Q. Why was this link assumed in the 2017R RFP process?**

13 A. This link was assumed in the RFP process related to new transmission and new wind
14 in the transmission-constrained areas of Wyoming. Given that wind generation is at
15 the bottom of the stack in any generation mix, it was reasonable to add the link to
16 assess how the resources will move on the available path due to potential EIM
17 transmission availability. In addition, the RFP did not include an out-of-model
18 adjustment to capture the EIM benefits associated with the additional wind.

19 Including this virtual link directly in the GRID model will cause double
20 counting of the EIM benefits. The GRID model is used to reflect the system
21 optimization at hourly level. Inter-regional EIM benefits are added as an out-of-
22 model adjustment to reflect EIM sub-hour market benefits. Furthermore, incremental
23 transmission from increasing participant EIM entities will be available to the entire

1 EIM footprint, not just PacifiCorp. To model this intra-hour transmission capacity
2 using only PacifiCorp's resource is incorrect and overstates the benefit.

3 **J. Energy Vision 2020 Line Losses**

4 **Q. AWEC proposes an adjustment to decrease NPC by \$0.7 million to account for**
5 **the line loss benefits resulting from the construction of the Aeolus-to-**
6 **Bridger/Anticline transmission line.⁹² How do you respond?**

7 A. The Company agrees to accept this adjustment proposed by AWEC in this case.
8 Reducing the load by 11.6 MW in eastern Wyoming area results in a reduction to
9 NPC by \$600,000 on Oregon-allocated basis.

10 **K. Energy Vision 2020 Reliability Benefits**

11 **Q. AWEC proposes an adjustment that decreases NPC by \$1.1 million to account**
12 **for the increased reliability benefits resulting from the construction of the**
13 **Aeolus-to-Bridger/Anticline transmission line.⁹³ Please explain.**

14 A. A derate assumption to the transmission path from eastern Wyoming to Aeolus area
15 was applied in the Company's IRP model before Energy Vision 2020. After Energy
16 Vision 2020 becomes effective at the end of 2020, this transmission path was
17 upgraded to the new capacity and the derate assumption was removed from the IRP
18 model. AWEC recommends that the Company make the same adjustment to GRID
19 topology transmission capacity in the TAM.

20 **Q. How does the Company respond to this recommendation?**

21 A. In the 2021 TAM, the GRID topology was updated to reflect new transmission
22 capacity from Energy Vision 2020 and the specific transmission links between

⁹² AWEC/100, Mullins/6.

⁹³ AWEC/100, Mullins/7.

1 eastern Wyoming and Aeolus are increased from 400 MW to 1900 MW, which fully
2 offset the derate impact as proposed by AWEC.

3 **VII. DIRECT ACCESS CONSUMER OPT-OUT CHARGE**

4 **Q. Did the Company calculate the direct access Consumer Opt-Out Charge**
5 **consistent with the settlement in the 2019 TAM and the settlement approved as a**
6 **result of the remand of the 2016 TAM?**

7 A. Yes. The Company calculated the Consumer Opt-Out Charge such that Schedule 200
8 is held constant for years six through 10.

9 **Q. Did Calpine Solutions dispute the Company's calculation?**

10 A. No. Calpine Solutions testifies that the Company's filing is "consistent with prior
11 agreements negotiated between the Company, Calpine Solutions and other parties, as
12 well as prior Commission orders."⁹⁴

13 **Q. Did any other party challenge the methodology used to determine the Consumer**
14 **Opt-Out Charge?**

15 A. Yes. AWEC recommends a change to the methodology for calculating the Consumer
16 Opt-Out Charge. AWEC is critical of the fact that the Consumer Opt-Out Charge
17 recovers 10-years of fixed generation costs over the five-year transition period.

18 **Q. How does the Consumer Opt-Out Charge operate together with Schedule 200?**

19 A. In the first five years after the direct access customer elects to leave, the customer
20 pays the actual Schedule 200 costs, as those costs change during that five-year period.

⁹⁴ Calpine Solutions/100, Higgins/4. Mr. Higgins' noted that his conclusion was contingent on reviewed supplemental discovery from the Company. As of the date of this filing, Mr. Higgins has not informed the Company that his position has changed.

1 If the Company adds incremental generation during those five years and those costs
2 flow into Schedule 200, the direct access customer pays those costs.

3 The Consumer Opt-Out Charge accounts for forecast Schedule 200 costs for
4 years six through 10. To do this, the Company holds the Schedule 200 costs constant
5 to develop a forecast of Schedule 200 costs for years six through 10. The Consumer
6 Opt-Out Charge is then calculated by taking the forecast Schedule 200 costs and
7 reducing them back to calculate a levelized payment made in years one through five.
8 Together, through the payment of Schedule 200 and the Consumer Opt-Out Charge,
9 departing customers pay the Company's fixed generation costs for 10 years (offset by
10 the value of freed-up energy).

11 **Q. AWEC recommends that the Commission reevaluate the use of a 10-year period**
12 **to calculate of the consumer opt-out charge.⁹⁵ What is the basis for AWEC's**
13 **recommendation?**

14 A. AWEC points out that PacifiCorp's Consumer Opt-Out Charge is different from
15 PGE's.⁹⁶ But when the Commission first directed PacifiCorp to develop a five-year
16 opt-out program, it specifically allowed the Company to "tailor its program to fit its
17 circumstances" and "acknowledg[ed] Pacific Power's concerns that any program that
18 allows customers to elect direct access permanently be tailored for each utility, be
19 designed to protect other customers from cost-shifting, and be limited to large,

⁹⁵ AWEC/100, Mullins/26.

⁹⁶ AWEC/100, Mullins/17.

1 sophisticated customers.”⁹⁷ PacifiCorp’s five-year direct access program has always
2 differed from PGE’s and that fact is no basis for modifying PacifiCorp’s program.

3 **Q. AWEC claims that the 10-year period was based on Section X of the 2010**
4 **Protocol, which is no longer in effect.⁹⁸ Do you agree?**

5 A. No. The fact that Section X of the 2010 Protocol no longer applies does not, in any
6 way, reduce the cost shifting that would occur absent the Consumer Opt-Out Charge.
7 By way of background, when the consumer opt-out charge was approved in 2015,
8 PacifiCorp’s interjurisdictional cost allocation methodology in effect at that time (the
9 2010 Protocol) included a provision (Section X) that required that the costs to serve
10 departing direct access load would continue to be assigned to Oregon even after the
11 load departs. AWEC is correct that the Company raised concerns that Section X of
12 the 2010 Protocol would contribute to the cost-shifting that would occur without a
13 Consumer Opt-Out Charge. But AWEC fails to note that the Commission’s approval
14 of the Consumer Opt-Out Charge did not rely on the terms of the 2010 Protocol when
15 finding that the Consumer Opt-Out Charge was necessary to prevent cost-shifting:

16 We conclude that the consumer opt-out charge is necessary
17 pursuant to implementation of the state's direct access laws by
18 our rules. The inclusion of an opt-out charge is consistent with
19 our request that PacifiCorp design a five-year opt-out program
20 that would protect other customers from cost-shifting. . .

21 The Stipulating Parties failed to rebut PacifiCorp’s evidence of
22 transition costs, up to approximately \$60 million, in years six to
23 ten of the program, and rely too heavily on mere assertions about
24 how transition costs beyond year five can be reduced or erased.⁹⁹

⁹⁷ *In the Matter of Public Utility Commission of Oregon Investigation of Issues Relating to Direct Access*,
Docket No. UM 1587, Order No. 12-500 at 9 (Dec. 30, 2012).

⁹⁸ AWEC/100, Mullins/18.

⁹⁹ Order No. 15-060 at 6-7.

1 Thus, the fact that the 2010 Protocol is no longer in effect does not require the
2 Commission to revisit its determination that PacifiCorp will experience transition
3 costs in years six through 10.

4 **Q. Did AWEC provide any analysis showing that using a less-than-10-year period**
5 **to calculate the Consumer Opt-Out Charge would prevent cost-shifting?**

6 A. No. AWEC's recommendation is based almost entirely on the simplistic argument
7 that because the 2010 Protocol is no longer in effect, the Consumer Opt-Out Charge
8 should utilize a shorter transition period. Notably, the 2010 Protocol was replaced in
9 2016, yet the Commission has never found that the Consumer Opt-Out Charge must
10 be modified as a result.

11 **Q. AWEC also claims that reducing the 10-year time period will "help Oregon**
12 **avoid acquiring new resources" because customers opting into the five-year**
13 **direct access program will reduce Oregon loads.¹⁰⁰ Do you agree?**

14 A. No. AWEC simply assumes this is the case without actually providing any evidence
15 supporting this assertion. This argument is similar to the one the Commission
16 rejected when it first approved the Consumer Opt-Out Charge. In that case, the
17 Commission rejected the argument that "PacifiCorp's system load growth will
18 completely mitigate any transition costs," because "GRID considers forecasted
19 system load growth in calculating both the transition adjustments and the consumer
20 opt-out charge."¹⁰¹ Here, AWEC claims that load decrease will mitigate transition
21 costs, but AWEC provides nothing more than the "mere assertions" the Commission
22 found insufficient in Order No. 15-060.

¹⁰⁰ AWEC/100, Mullins/18.

¹⁰¹ Order No. 15-060 at 7.

1 **Q. What time period does AWEC recommend using to determine the transition**
2 **period for the Consumer Opt-Out Charge?**

3 A. AWEC does not recommend a specific time period. Instead, AWEC recommends
4 using proposed coal plant retirement dates to set the period over which the Consumer
5 Opt-Out Charge is calculated.¹⁰² Although AWEC’s recommendation is not entirely
6 clear, it fails to address the underlying reason that the Commission approved the
7 Consumer Opt-Out Charge—which is to prevent cost-shifting. AWEC provided no
8 analysis showing that its proposal would not shift costs. Without any of this analysis,
9 there is no basis to fundamentally change how the five-year program operates.

10 **Q. Do you have any other concerns about AWEC’s proposal?**

11 A. Yes. Although AWEC frames its proposal as a modification to the calculation of the
12 Consumer Opt-Out Charge, AWEC’s recommendation amounts to dramatic and
13 fundamental redesign of PacifiCorp’s five-year direct access program. That
14 recommendation is better suited for the concurrent investigation into direct access
15 issues that the Commission is undertaking in docket UM 2024.

16 **Q. Does this conclude your reply testimony?**

17 A. Yes.

¹⁰² AWEC/100, Mullins/18-19.

Docket No. UE 375
Exhibit PAC/501
Witness: David G. Webb

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of David G. Webb
2021 TAM Oregon-Allocated Net Power Costs Reply Filing

June 2020

PacifiCorp
CY 2021 TAM
Reply Filing

Line no	ACCT.	Total Company				Factor	Oregon Allocated				
		UE-356	TAM	TAM			Factors	Factors	UE-356	TAM	
		CY 2020 - Final Update	CY 2021 - Initial Filing	CY 2021 - Reply Filing			CY 2020	CY 2021	CY 2020 - Final Update	CY 2021 - Initial Filing	CY 2021 - Reply Filing
Sales for Resale											
1	447	7,454,128	7,542,788	7,364,161	SG	26.456%	26.023%	1,972,052	1,962,832	1,916,348	
2	447	-	-	-	SG	26.456%	26.023%	-	-	-	
3	447	422,493,915	274,078,000	246,508,905	SG	26.456%	26.023%	111,774,336	71,322,311	64,148,107	
4	447	-	-	-	SE	25.314%	25.101%	-	-	-	
5	447	429,948,043	281,620,789	253,873,066				113,746,388	73,285,143	66,064,455	
6											
7											
Total Sales for Resale											
Purchased Power											
8	555	11,573,498	2,848,086	2,847,480	SG	26.456%	26.023%	3,061,867	741,147	740,989	
9	555	3,793,812	2,484,823	2,484,823	SG	26.456%	26.023%	1,003,685	646,616	646,616	
10	555	37,613,980	15,046,383	15,044,970	SE	25.314%	25.101%	9,521,753	3,776,866	3,776,511	
11	555	674,728,706	592,134,446	608,735,645	SG	26.456%	26.023%	178,505,181	154,088,971	158,409,040	
12	555	-	-	-	SE	25.314%	25.101%	-	-	-	
13	555	7,454,837	-	-	SG	26.456%	26.023%	1,972,240	-	-	
14	555	735,164,833	612,513,738	629,112,919				194,064,726	159,253,600	163,573,157	
15											
16											
Wheeling Expense											
17	565	22,079,714	21,615,814	21,615,814	SG	26.456%	26.023%	5,841,375	5,625,004	5,625,004	
18	565	-	-	-	SG	26.456%	26.023%	-	-	-	
19	565	106,215,175	114,763,115	114,742,965	SG	26.456%	26.023%	28,100,122	29,864,384	29,859,140	
20	565	3,175,158	2,694,259	2,694,259	SE	25.314%	25.101%	803,772	676,299	676,299	
21		131,470,047	139,073,187	139,053,037				34,745,269	36,165,687	36,160,443	
22											
23											
Total Wheeling Expense											
Fuel Expense											
24	501	655,082,891	612,737,366	576,061,622	SE	25.314%	25.101%	165,830,293	153,806,196	144,600,039	
25	501	36,986,850	-	-	SE	25.314%	25.101%	9,362,999	-	-	
26	501	7,690,635	6,894,972	6,196,453	SE	25.314%	25.101%	1,946,838	1,730,741	1,555,402	
27	501	297,308,679	303,050,501	301,951,689	SE	25.314%	25.101%	75,261,903	76,070,185	75,794,367	
28	547	4,355,357	3,721,741	3,344,450	SE	25.314%	25.101%	1,102,532	934,212	839,507	
29	547	4,676,489	4,519,705	4,508,022	SE	25.314%	25.101%	1,183,825	1,134,513	1,131,580	
30	503	1,006,100,902	930,924,285	892,062,236				254,688,390	233,675,847	223,920,895	
31											
32											
33	TAM Settlement Adjustment**	(1,467,719)	-	-		As Settled		(388,297)	-	-	
34											
35	Net Power Cost (Per GRID)	1,441,320,020	1,400,890,421	1,406,355,126				369,363,700	355,809,991	357,590,040	
36											
37	Oregon Situs NPC Adjustments	522,082	786,770	846,893	OR	100.000%	100.000%	522,082	786,770	846,893	
38	Total NPC Net of Adjustments	1,441,842,102	1,401,677,191	1,407,202,019				369,885,782	356,596,762	358,436,933	
39											
Non-NPC EIM Costs*											
40	Production Tax Credit (PTC)	1,456,461	-	-	SG	26.456%	26.023%	385,319	-	-	
41		(96,935,002)	(248,328,203)	(248,328,203)	SG	26.456%	26.023%	(25,644,974)	(64,621,536)	(64,621,536)	
42	Total TAM Net of Adjustments	1,346,363,561	1,153,348,988	1,158,873,816				344,626,127	291,975,226	293,815,397	
43											
44											
45											
46											
47											
48											
49											
50											
*EIM Benefits for the 2020 TAM are reflected in net power costs											
**TAM Settlement UE 356 - Agreed to decrease Oregon-allocated NPC by \$388,297.											
Increase Including Load Change \$ (49,210,532) \$ (47,370,361)											

*EIM Benefits for the 2020 TAM are reflected in net power costs

**TAM Settlement UE 356 - Agreed to decrease Oregon-allocated NPC by \$388,297.

Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-356 \$344,626,127
\$ Change due to load variance from UE-356 forecast (3,440,369)
2021 Recovery of NPC (incl. PTC) in Rates \$341,185,758

Increase Absent Load Change (50,810,730)

Increase Including Load Change \$ (49,210,532) \$ (47,370,361)

Docket No. UE 375
Exhibit PAC/502
Witness: David G. Webb

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of David G. Webb
2021 Results of Updated Net Power Cost Study Reply Filing

June 2020

PacifiCorp

Reply ORTAM21 NPC CONF

Net Power Cost Analysis

\$

12 months ended December 2021

01/21-12/21

Jan-21

Feb-21

Mar-21

Apr-21

May-21

Jun-21

Jul-21

Aug-21

Sep-21

Oct-21

Nov-21

Dec-21

Special Sales For Resale

Long Term Firm Sales

Black Hills	7,364,161	735,592	536,044	438,907	366,465	359,080	627,234	734,966	736,484	722,187	693,527	671,361	742,313
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	10,163	847	847	847	847	847	847	847	847	847	847	847	847
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	98,745	6,617	6,442	7,876	4,901	5,474	5,482	14,296	13,900	10,935	8,304	6,617	7,901
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-

Total Long Term Firm Sales

	7,473,069	743,056	543,333	447,631	372,213	365,401	633,564	750,109	751,231	733,969	702,678	678,825	751,061
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Short Term Firm Sales

COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	3,858,540	650,930	590,520	654,570	-	-	-	-	-	-	661,360	639,800	661,360
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	767,600	252,500	242,400	272,700	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	4,870,100	1,646,150	1,524,600	1,699,350	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
WestMain	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-

Total Short Term Firm Sales

	9,496,240	2,549,580	2,357,520	2,626,620	-	-	-	-	661,360	-	661,360	639,800	661,360
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System Balancing Sales

COB	47,675,320	5,056,000	2,954,616	2,697,064	1,643,525	3,631,194	2,855,798	4,270,830	4,433,760	5,784,159	4,276,398	5,101,102	4,970,875
Four Corners	65,703,408	6,243,282	3,739,513	3,380,785	2,959,214	2,413,766	4,634,173	6,413,788	8,266,746	10,430,846	5,571,125	4,543,070	7,107,099
Mead	30,346,469	3,536,328	2,612,058	2,418,713	2,138,740	1,709,046	1,890,963	1,410,253	3,748,316	2,555,066	2,909,783	2,699,102	2,718,103
Mid Columbia	25,537,125	2,620,395	480,693	417,962	1,990,590	2,167,731	1,108,939	4,702,278	4,532,608	2,775,953	2,284,515	1,460,106	995,356
Mona	27,574,789	2,829,348	1,525,439	838,757	711,888	1,430,787	2,548,576	3,007,008	2,843,204	4,890,178	2,343,600	2,028,380	2,577,624
NOB	1,479,324	-	-	99,052	520,323	-	-	607,640	252,309	-	-	-	-
Palo Verde	38,483,260	2,211,385	456,278	2,011,967	1,096,528	3,788,464	5,838,505	7,694,213	5,560,140	2,594,875	1,234,794	1,245,725	4,750,387
Trapped Energy	104,062	95,390	270	-	590	-	-	-	-	-	3,138	2,067	2,607

Total System Balancing Sales

	236,903,757	22,592,128	11,768,866	11,864,300	11,061,397	15,140,988	18,876,954	28,106,010	29,637,082	29,031,076	18,623,353	17,079,552	23,122,052
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Total Special Sales For Res

	253,873,066	25,884,764	14,669,719	14,938,551	11,433,610	15,506,388	19,510,517	28,856,119	30,388,313	29,765,045	19,987,391	18,398,177	24,534,472
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[illegible]

Qualifying Facilities	2,468,928	216,310	237,207	267,853	313,290	303,374	244,837	166,837	139,017	130,925	134,349	138,692	174,234
QF California	8,526,013	685,205	622,486	675,919	549,840	791,695	853,072	804,323	706,952	676,893	710,906	692,968	775,754
QF Idaho	51,801,171	3,002,824	3,169,852	4,140,008	5,143,180	5,590,917	5,823,344	5,679,229	5,370,766	4,654,714	3,670,563	2,717,089	2,838,685
QF Oregon	11,686,984	799,972	834,747	994,336	1,035,869	1,137,833	1,155,642	1,078,323	1,069,390	1,006,203	958,094	845,641	770,935
QF Utah	208,630	14,566	13,067	14,455	3,598	16,682	34,292	47,832	51,603	41,039	13,584	-	-
QF Washington	148,999	14,566	13,067	14,455	11,422	10,419	8,672	12,538	12,397	9,613	12,059	12,525	17,264
QF Wyoming	14,791,130	1,137,736	1,042,736	1,192,638	1,605,813	1,011,587	995,146	1,437,452	1,393,486	1,388,503	1,437,697	1,426,922	721,416
Blomass One QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	137,080	3,234	5,370	4,809	4,672	4,536	6,740	21,381	26,379	25,132	16,973	11,157	6,697
Enterprise Solar I QF	12,565,251	618,303	756,852	985,653	1,115,324	1,255,980	1,384,633	1,549,498	1,503,902	1,182,205	958,096	707,925	546,881
Escalante Solar I QF	11,633,431	567,021	680,951	928,583	1,019,621	1,191,002	1,306,995	1,424,978	1,390,261	1,093,877	875,343	645,179	509,621
Escalante Solar II QF	10,913,161	532,831	639,708	835,963	959,353	1,125,876	1,236,165	1,346,489	1,305,289	1,031,715	820,808	603,620	475,344
Escalante Solar III QF	10,508,750	518,662	625,371	809,560	927,465	1,098,872	1,207,167	1,309,506	1,268,668	1,003,541	751,202	552,982	435,755
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,449,185	516,272	844,647	761,925	794,324	483,155	552,309	637,981	597,909	755,820	737,311	884,763	882,768
Foot Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar	10,904,092	549,588	617,041	897,068	990,647	1,158,077	1,259,308	1,331,161	1,260,573	977,914	811,198	583,169	468,346
Granite Mountain West Sola	7,225,470	363,870	408,682	599,461	658,359	766,651	833,319	881,233	834,746	646,982	536,860	385,681	309,627
Iron Springs Solar QF	11,192,631	635,330	664,037	898,798	1,017,392	1,129,261	1,284,984	1,341,703	1,318,741	1,005,130	816,809	579,976	500,469
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,740	1,007,477	917,570	1,126,955	897,120	856,897	745,979	673,722	567,152	616,686	799,252	709,690	

Total Long Term Firm Purchases	536,182,170	42,689,706	40,870,047	46,740,392	46,209,400	45,799,662	47,373,450	48,950,855	47,426,757	44,074,402	42,954,597	41,759,962	41,332,940
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[illegible][illegible]

Total Purchased Power & N

Gas Fuel Burn Expense

Total Gas Fuel BurnTotal Gas Fuel Burn Expense

Other Generation

[illegible]

Integration Charge

Total Other Generation

Net Power Cost

4,508,022	426,235	331,528	424,364	403,150	404,602	374,699	386,531	390,231	391,642	335,785	333,779	305,477
1,406,355,126	118,848,642	114,805,435	108,460,446	107,245,779	105,553,154	113,499,932	141,181,420	135,420,875	110,550,363	112,417,493	117,841,877	120,529,708

Docket No. UE 375
Exhibit PAC/503
Witness: David G. Webb

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of David G. Webb

2021 Updates Summary Reply Filing

June 2020

Oregon TAM 2021 (February 2020 Initial Filing)	NPC (\$) =	1,400,890,421
	\$/MWh =	23.14

	Impact (\$) Oregon Allocated Basis	NPC (\$) Total Company
Accepted Adjustments		
A01 - Line Loss Benefits	(599,839)	
Updates		
U01 - Official Forward Price Curve and Short Term Firm Transactions	3,847,603	
U02 - EIM Benefits	4,008,862	
U03 - Long Term Contracts	624,813	
U04 - Coal Cost	(6,568,331)	
U05 - Pipeline Expense	212,525	
Total Changes =	1,525,635	5,464,705
Total Change from February 2020 Initial Filing		
Oregon TAM 2021 (Reply Filing)	NPC (\$) =	1,406,355,126
	\$/MWh =	23.27

REDACTED

Docket No. UE 375

Exhibit PAC/600

Witness: Seth Schwartz

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

REDACTED

Reply Testimony of Seth Schwartz

June 2020

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ATTACHED EXHIBITS

Exhibit PAC 601 – Seth Schwartz’ Resume

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 that 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 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

1 well as the Federal Energy Regulatory Commission (FERC). My current resume is
2 attached at Exhibit PAC/601. I have a Bachelor of Science in Geological Engineering
3 degree from Princeton University.

4 **Q. Have you testified in previous regulatory proceedings?**

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

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

14 A. Yes. In 1991, following the merger of Utah Power & Light and PacifiCorp, I directed
15 a study of the coal supply operations and fuel procurement practices of PacifiCorp on
16 behalf of the seven state¹ public service commissions and FERC, as well as a
17 subsequent update in 1995. These studies were comprehensive reviews of the
18 management of the mining operations and coal supply plan for all of PacifiCorp's
19 coal-fired generation facilities. In 2011, I also testified on behalf of the Utah Office
20 of Consumer Services in Docket No. 10-035-124 regarding PacifiCorp's fuel supply
21 management and coal supply operations. I have also testified on behalf of PacifiCorp
22 in the states of Oregon, California, Idaho, Utah, Washington, and Wyoming.

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

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

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

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

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

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

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

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

20 A. The subject of my testimony was regarding the structure of coal markets in the United
21 States in general and for PacifiCorp's power plants in particular, the role of multi-
22 year coal contracts in supplying reliable and economic fuel for plant operations, and

1 the function of take-or-pay and liquidated damage provisions in long-term coal
2 supply contracts.

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

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

17 **II. PURPOSE AND SUMMARY OF TESTIMONY**

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

19 A. I respond to the opening testimony of Mr. Ed Burgess, filed on behalf of Sierra
20 Club, challenging PacifiCorp's coal fuel expenditures.

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

1 **Q. Please summarize your testimony.**

2 A. My testimony:

- 3 • Rebutts the claim by Mr. Burgess that fuel adjustment proceedings like the
4 transition adjustment mechanism (TAM) are not used by regulatory
5 commissions in general, and the Commission in particular, to review the
6 prudence of a utility's fuel procurement decisions;
- 7 • Explains how it is standard utility practice to use the incremental cost of
8 generation to dispatch power plants, not the average cost, and how this
9 practice minimizes the cost of generation for customers;
- 10 • Describes the structure of the coal markets in general and the need for multi-
11 year coal supply agreements to provide reliable and economic fuel supply for
12 power plants located in areas with relatively illiquid coal markets;
- 13 • Supports the need for minimum volume provisions in multi-year coal supply
14 agreements and the use of take-or-pay and liquidated damage provisions;
- 15 • Shows that Mr. Burgess cannot use the FERC Form 1 filings by the Company
16 to determine the non-fuel variable operation and maintenance costs for its
17 power plants;
- 18 • Refutes the claim by Mr. Burgess that the Company should be using the
19 average cost of fuel to project the dispatch of its coal plants in the 2021 TAM
20 and exposes the flaws in his methodology to calculate "adjustments" to the
21 2021 TAM using the "benchmark" projected cost of the Company's natural
22 gas generation;
- 23 • Rejects the recommendation by Mr. Burgess that the entire cost of two of the

1 Company's coal supply contracts be excluded from the 2021 TAM with no
2 attempt to show imprudence in the decisions to enter into these contracts; and,
3 • Clarifies that coal contract provisions for changes in environmental laws and
4 regulations do not provide the Company with the ability to "renegotiate" the
5 contracts without the precondition occurring.

6 **III. PURPOSE AND REGULATORY REVIEW OF FUEL**
7 **ADJUSTMENT PROCEEDINGS**

8 **Q. In his testimony, Mr. Burgess opines that "many fuel adjustment clauses like the**
9 **TAM are approved annually by state utility commissions on a somewhat routine**
10 **basis and without much scrutiny."**³ **Do you agree with this opinion?**

11 A. No.

12 **Q. What is the purpose of a fuel adjustment clause or proceeding?**

13 A. Fuel adjustment clauses or proceedings are used by most utility regulatory
14 commissions to provide for the direct cost recovery of volatile energy costs for power
15 supply (primarily fuel costs for power generation and purchased power costs). They
16 are intended to recover the actual costs for large generation expenditures that can vary
17 significantly with changes in fuel and power market prices outside of the control of
18 the regulated utility. They typically provide for a true-up for utilities to recover
19 actual costs and to refund over-charges.

20 **Q. How does the fuel adjustment clause process work in Oregon and elsewhere?**

21 A. Typically, the regulated utility submits to the utility commission the records of its
22 actual costs for fuel and purchased power to supply electricity to customers. The

³ Sierra Club/100, Burgess/9.

1 utility commission can review the actual charges and the prudence of the utility's fuel
2 and power procurement decisions. In Oregon, PacifiCorp annually files its forecast
3 net power costs in the TAM, where the forecast is subject to Commission review.
4 PacifiCorp's actual net power costs are trued up through an annual power cost
5 adjustment mechanism (PCAM) filing, subject to deadbands, sharing bands and an
6 earnings test.

7 **Q. Have you testified in fuel adjustment clause proceedings?**

8 A. Yes. Other EVA principals and I have testified numerous times in regulatory
9 proceedings regarding fuel adjustment clauses at state utility commissions and at the
10 FERC. Our clients have included state commissions, regulated utilities, and power
11 customers.

12 **Q. Is it your experience that utility filings in fuel adjustment proceedings like the**
13 **TAM are approved without much scrutiny?**

14 A. No. In some states, the fuel adjustment clause is subject to a regular audit of the
15 prudence of management practices. In other jurisdictions, the fuel adjustment clause
16 is subject to a prudence review based on the action of the commission staff or
17 intervenors. Decisions and expenses that are deemed imprudent are subject to
18 disallowance.

19 **Q. In your experience, has the Commission previously reviewed the prudence of**
20 **PacifiCorp's fuel procurement decisions?**

21 A. Yes. In docket UM 1712 in 2015, the Commission heard testimony regarding the
22 prudence of the long-term coal supply contract for the Huntington power plant. In
23 docket UE 323 in 2017, the Commission heard testimony regarding the prudence of

1 the long-term coal supply contract for the Naughton plant and the Company's plans
2 for a new, multi-year coal supply contract for the Jim Bridger plant.

3 **Q. Did Sierra Club sponsor testimony in these cases?**

4 A. Yes. Sierra Club sponsored witnesses in both cases. These witnesses raised similar
5 objections as Mr. Burgess in this case – that the Company should not enter into coal
6 supply contracts with commitments to take a minimum amount of coal. These cases
7 are further described in Mr. Ralston's testimony.

8 **Q. Mr. Burgess testified that the TAM is not "the appropriate venue for the**
9 **Commission to review multi-year fuel contract decisions. Do you agree?**

10 A. No. Fuel contracting decisions (whether for short-term or long-term purchases) are
11 made on a regular basis and it is appropriate for the Commission to review these
12 decisions annually in a fuel adjustment clause proceeding like the TAM. That is the
13 practice of other utility commissions in my experience. It is appropriate to review the
14 prudence of these decisions close to the time period when the decisions are made, not
15 in a general rate case that may not happen for years after the fuel procurement
16 decisions.

IV. USE OF INCREMENTAL GENERATION COSTS FOR POWER

PLANT DISPATCH

Q. Mr. Burgess testifies that PacifiCorp uses the “dispatch tier” of costs in its production cost model, Generation and Regulation Initiative Decision Tools (GRID), to estimate its coal plant dispatch.⁴ What is the purpose of using a “dispatch tier” in a production cost model?

A. 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.

Q. Is it unusual in the power industry to use the incremental cost for plant operations in making dispatch decisions?

A. No. It is the standard practice of regulated utilities, merchant power generators, and independent system operators to use the incremental cost of generation in plant dispatch decisions. My company operates our own production cost model that we use to simulate and project power plant operations. We use the incremental cost of generation in our production cost modeling, just as utilities do, in order to simulate the operation of the generation fleet.

Q. What is the difference between the incremental cost and the average cost of power plant generation?

A. The incremental cost is the change in cost to generate additional generation from each power plant. The incremental costs include the cost to purchase additional fuel, the

⁴ Sierra Club/100, Burgess/32.

1 incremental heat rate (efficiency) to operate the plant, and the variable non-fuel
2 generation costs for additional generation. The average cost includes all fuel and
3 variable non-fuel costs for generation. This incremental cost used for dispatch can be
4 above or below the average net power cost included in net power costs in the TAM.

5 **Q. What is the difference between the average cost and the incremental cost of coal**
6 **to operate a coal-fired power plant?**

7 A. The average cost of coal is the cost to purchase and deliver all of the coal burned at
8 the power plant in a given period of time, divided by the heat content of the coal (the
9 cost per million British thermal unit). The incremental cost of coal is the cost to
10 purchase an additional amount of coal to supply additional generation.

11 **Q. Why do the average cost and the incremental cost of coal differ?**

12 A. The average cost of coal includes all of the cost of coal purchases under existing coal
13 contracts or from company mining operations. In the case of purchased coal from
14 third parties, the cost of coal purchased under contracts is fixed well in advance of
15 delivery and may differ substantially from the cost to purchase additional coal at
16 market prices. In the case of coal supplied from company mining operations, the
17 average cost reflects the full operating costs for the mine, while the incremental cost
18 reflects the cost to mine additional coal. Third-party coal contracts may also have
19 “tiered” pricing where incremental purchases are priced separately (typically below)
20 the price for the base contract quantity.

1 **Q. Is it common for there to be a difference in the average cost of coal purchased**
2 **under contracts and the incremental cost for additional coal purchases at**
3 **market prices?**

4 A. Yes. All coal is purchased under physical contracts committed in advance of
5 delivery. These contracts are priced at the market price at the time of the contract
6 commitment. The price for additional coal purchases at the time of plant dispatch
7 will vary from the average cost of coal purchased under forward contracts, either for
8 new purchases at market prices or for incremental purchases under existing contracts
9 at different pricing tiers. The incremental price may be above or below the average
10 price of coal contract commitments.

11 **Q. Is it prudent utility practice to use the incremental cost of coal for dispatch**
12 **decisions?**

13 A. Yes. The average cost of coal is the cost of all coal purchases, including the sunk
14 cost of previous purchase commitments and the cost of additional coal purchases
15 above the minimum purchases under existing contracts. The incremental cost is the
16 cost of additional coal purchases to supply additional generation. The use of the
17 incremental cost of coal minimizes the total cost of generation for the customer. In
18 my experience, all utilities use the incremental cost of coal to dispatch their coal
19 power plants.

20 **Q. Is the decision process the same for power plants fueled by natural gas?**

21 A. Yes. Utilities commonly enter into forward contracts for natural gas purchases,
22 including commodity and transportation. Utilities dispatch their gas-fired plants
23 based on the incremental cost of natural gas (the daily cash market price) and ignore

1 the sunk costs of firm gas transmission contracts and hedges for gas commodity
2 prices.

3 **Q. How do utilities and merchant power generators dispatch coal plants that have**
4 **captive coal operations?**

5 A. Whether a regulated utility or merchant generator, the power company dispatches the
6 power plant based on the incremental cost of coal production – not the average cost.
7 The incremental cost reflects the additional cost to produce additional coal and does
8 not include the fixed mine costs.

9 **Q. Mr. Burgess testifies that “By understating the cost to dispatch coal, coal plants**
10 **are excessively run, thus displacing lower cost resources at the expense of**
11 **ratepayers...”⁵ Do you agree?**

12 A. No. Mr. Burgess objects to the use of incremental costs (the “dispatch tier”) in the
13 GRID model rather than the average cost (the “costing tier”) to dispatch PacifiCorp’s
14 coal-fired power plants. The incremental cost of generation is the proper cost to use
15 in dispatching all power plants (not just coal) and the use of incremental costs
16 *minimizes* total costs charged to the ratepayer. This is standard practice among all
17 utilities and independent system operators for dispatching power plants to reduce total
18 costs of generation.

⁵ Sierra Club/100, Burgess/1.

1 **Q. Mr. Burgess testifies that “the coal dispatch modeled in the TAM is inconsistent**
2 **with the recent analysis performed by PacifiCorp in its Integrated Resource**
3 **Plan (IRP).”⁶ Do you believe that is correct?**

4 **A.** No. The TAM is a short-term forecast of fuel costs for 2021. This forecast should
5 take into account all of the existing commitments and available resources in effect for
6 the forecast period, including the existing coal supply contracts. The IRP is a long-
7 term planning process evaluating power supply resource decisions for the next 20
8 years. Over this period of time, all of the Company’s existing contract commitments
9 will expire and the model assumes that power plants will be dispatched at the cost of
10 fuel projected for the forecast period. This is not inconsistent – it is prudent utility
11 practice.

12 **V. COAL MARKETS IN THE UNITED STATES AND THE ROLE OF**
13 **LONG-TERM COAL SUPPLY CONTRACTS**

14 **Q. Please provide an overview of the structure of coal markets in the United States.**

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

⁶ Sierra Club/100, Burgess/3.

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

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

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

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

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

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

1 **Q. How does coal transportation affect the ability of customers to purchase coal on**
2 **the “spot” market?**

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

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

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

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

22 A. Coal procurement strategies vary based upon the characteristics of the coal that the
23 markets that are the most economic supply to the power plant. In the more liquid coal

1 markets (with many competing coal producers), electric utilities typically purchase
2 most of their coal under contracts with a term of one to three year duration. In these
3 markets, utilities typically use a portfolio of coal contracts to commit to a minimum
4 level of purchases starting at 70 percent – 95 percent of expected burn in the first
5 year. Spot purchases made during the calendar year typically fill in for variations in
6 coal burn above the minimum burn expectations.

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

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

19 **Q. Why do coal supply contracts have “minimum take” provisions?**

20 A. Without a commitment by the customer to purchase a minimum amount of coal, the
21 coal supplier does not have an assured market for the output of the mine; the contract
22 is merely an option for the customer to purchase coal if desired while paying no cost
23 for this option. No coal producer could afford to agree to such a contract as it would

1 require a large investment of capital in reserves, development and equipment to be
2 available to supply coal with no assurance that any coal would be purchased. Further,
3 coal suppliers (and similarly coal transporters) require a commitment to purchase at a
4 regular rate (“ratable take”) to employ and maintain a workforce able to meet the
5 customer’s requirements. As a result, while some contracts may provide some
6 flexibility for the customer to vary purchase requirements, all coal supply contracts
7 have a minimum volume commitment to purchase coal.

8 **Q. What is the purpose of a “liquidated damages” provision in a coal supply**
9 **contract?**

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

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

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

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

21 A. In general, utilities do not include the fixed cost of liquidated damages in determining
22 the variable cost for the dispatch of their power plants. Customers benefit from least-
23 cost dispatch as utilities only include the variable cost of fuel in the decision whether

1 to operate a power plant (just as utilities would not include the fixed cost of a pipeline
2 contract for transportation of natural gas). If the power plant dispatches at the
3 variable cost (subtracting the liquidated damages from the full contract coal price) but
4 would not have dispatched at the full cost, the most economic decision is to dispatch
5 the power plant even though the fuel cost charged to the customer is greater than the
6 fuel cost used for dispatch purposes. If a power plant still does not dispatch
7 economically after subtracting the cost of liquidated damages, then the least-cost
8 decision is to reduce plant operations and pay the liquidated damages.

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

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

VI. NON-FUEL VARIABLE OPERATIONS & MAINTENANCE (O&M)

COSTS INCLUDED IN THE GRID MODEL

Q. Mr. Burgess opines that the non-fuel variable O&M costs used by PacifiCorp as inputs to the GRID model “artificially deflates the cost of running the coal units relative to other resources in the GRID model and thereby leads to an overestimation of coal generation...”⁷ What is the basis for his opinion?

A. Mr. Burgess compared the non-fuel variable O&M costs for each coal unit used as inputs to the GRID model with “those reported by PacifiCorp in its most recent FERC Form 1 filing (sourced from S&P Global Market Intelligence).”⁸

Q. What is the problem with the comparison of non-fuel variable O&M costs made by Mr. Burgess?

A. When utilities report power plant O&M costs of the FERC Form 1, they do not report a breakdown of these costs into “fixed” and “variable” costs. The market data service used by Mr. Burgess (S&P Global Market Intelligence, formerly SNL) provides its estimate of the breakdown of the reported non-fuel O&M costs into fixed and variable costs based on the “assumed” variable components of operating and maintenance expenses.”⁹ There is no way for S&P Global Market Intelligence to determine what amount of the non-fuel O&M expenses reported on the FERC Form 1 by PacifiCorp are variable. Thus, there is no basis for Mr. Burgess to opine that the inputs to the GRID model “artificially deflates the cost of running the coal units.”¹⁰

⁷ Sierra Club/100, Burgess/31.

⁸ Sierra Club/100, Burgess/30.

⁹ S&P Global, defines Variable Production Expense, “Variable production cost, including fuel and the assumed variable components of operating and maintenance expenses.” <https://platform.marketintelligence.spglobal.com>

¹⁰ Sierra Club/100, Burgess/31.

1 **Q. In your experience, what non-fuel O&M costs are typically considered to be**
2 **variable costs in the dispatch economics?**

3 A. In my experience, power companies (utilities and merchant generators) typically only
4 include consumables (such as reagent costs) in their non-fuel variable costs, while
5 other O&M costs (labor and maintenance) are considered to be mostly fixed costs.

6 **VII. RESPONSE TO SIERRA CLUB’S PROPOSED ADJUSTMENTS**

7 **Q. Sierra Club recommends a reduction to the 2021 TAM in the amount of \$144.4**
8 **million total company and \$36.2 million Oregon allocated. What is the basis of**
9 **this recommended reduction?**

10 A. Mr. Burgess testified that the Sierra Club’s recommended modifications to the 2021
11 TAM fall into two categories: “Corrections for uneconomic generation at
12 PacifiCorp’s coal units” and “Elimination of certain fixed fuel costs that are
13 inappropriately included in the 2021 TAM.”¹¹

14 **Q. How did Mr. Burgess “correct for uneconomic generation at PacifiCorp’s coal**
15 **units”?**

16 A. For five of the Company’s coal plants, Mr. Burgess “removed the coal fuel costs from
17 the 2021 TAM” and “assumed a replacement generation cost based on a benchmark
18 value.”¹² The “benchmark value” used by Mr. Burgess was “equal to the average of
19 PacifiCorp’s projected fuel costs for its natural gas resources in the proposed 2021
20 TAM (i.e. \$20.49/MWh).”¹³ The five coal plants are Jim Bridger, Hunter,
21 Huntington, Craig, and Hayden. Mr. Burgess testified that these plants either had no

¹¹ Sierra Club/100, Burgess/71.

¹² Sierra Club/100, Burgess/73.

¹³ *Id.*

1 minimum take coal provision in 2021 or that the dispatch in the GRID model was
2 above the minimum take amount.

3 **Q. What is the justification provided by Mr. Burgess that these coal plants have**
4 **“uneconomic generation”?**

5 A. Mr. Burgess testified that these five coal plants have “above average fuel costs with
6 the exception of Hunter” and that the dispatch was not constrained by minimum take
7 provisions in their coal supply contract.¹⁴

8 **Q. What was the methodology used by Mr. Burgess to calculate the “replacement**
9 **generation cost” for these “uneconomic” coal plants?**

10 A. Mr. Burgess assumed that the generation from these coal plants could be replaced at
11 “the average of PacifiCorp’s projected fuel costs for its natural gas resources in the
12 proposed 2021 TAM (i.e. \$20.49/MWh).”¹⁵

13 **Q. Is that a reasonable methodology for determining the replacement cost of**
14 **generation?**

15 A. No. By definition, the projected generation from these coal plants could not be
16 replaced at the average fuel cost of generation projected for the Company’s natural
17 gas plants. The replacement generation cost would be *higher* than the average cost
18 projected for the dispatch of the Company’s gas-fired plants.

¹⁴ Sierra Club/100, Burgess/72.

¹⁵ Sierra Club/100, Burgess/73.

1 **Q. Why would the replacement power costs be higher than the projected 2021**
2 **average cost of the Company’s gas-fired generation?**

3 A. Like all dispatch models, the Company’s GRID model projects that the Company’s
4 power plants will be dispatched with the lowest-cost plants operated first and the
5 incremental costs continue to rise as higher-cost plants are dispatched. The GRID
6 model is dispatching the lowest-cost natural gas resources first. If the generation
7 from these five coal plants were removed from the forecast, the Company would be
8 forced to dispatch plants with fuel costs higher than the average cost of the natural
9 gas plants dispatched by the model. Mr. Burgess has made no attempt to show that
10 generation would be available from the Company’s natural gas plants to replace this
11 coal-fired generation at all, but if it were, the costs would be higher than the average
12 in the GRID model – not equal to the average cost. Mr. David Webb provides this
13 analysis in his testimony.

14 **Q. Is Mr. Burgess correct in his assertion that “PacifiCorp has incorrectly**
15 **overestimated generation” at these five coal plants?¹⁶**

16 A. No. Mr. Burgess objects to the fact that PacifiCorp uses the incremental costs for fuel
17 in its dispatch model rather than the average cost of fuel. As I testified above, in my
18 opinion, PacifiCorp is correct in using the incremental cost of coal fuel in its dispatch
19 model, just as it uses the incremental cost for natural gas fuel, the incremental cost for
20 purchased power and the incremental cost for plant operations. The use of
21 incremental costs for plant dispatch minimizes the total cost of power supply for
22 customers.

¹⁶ Sierra Club/100, Burgess/72.

1 **Q. Which power plants account for the majority of the 2021 TAM adjustment**
2 **recommended by Mr. Burgess due to “uneconomic generation forecasted at**
3 **PacifiCorp’s coal units”?**

4 A. The majority of the adjustments recommended by Mr. Burgess occur at the Jim
5 Bridger and Huntington plants. The recommended adjustments at the Craig and
6 Hayden plants are minimal because the projected average cost of fuel at the Craig
7 plant is almost the same as the projected fuel cost for the Company’s gas resources
8 and the additional generation at the Hayden plant above the minimum contract
9 quantity is small. For the Hunter plant, the projected cost of fuel is actually below the
10 projected cost of gas resources.

11 **Q. What is the reason that the Jim Bridger plant has projected average fuel costs**
12 **above the incremental costs used in the GRID model?**

13 A. The primary reason is the fixed cost incurred to maintain and operate the Company’s
14 Bridger Coal Company mine. These fixed costs include the labor, maintenance and
15 equipment costs required to have the coal mine capable of operating to supply fuel to
16 the Jim Bridger plant.

17 **Q. Is Mr. Burgess correct that the Company could save money by reducing the coal**
18 **production at Bridger Coal Company in 2021 and replacing the plant generation**
19 **with power from its natural gas resources?**

20 A. No. The fixed costs at Bridger Coal Company are required to have the mine available
21 to provide fuel to supply the Jim Bridger plant in 2021. If the Company were to close
22 the mine in 2021 to reduce these fixed costs (laying off the work force and ceasing
23 maintenance activities), the Bridger Coal Company mine would no longer be

1 available to supply fuel to the Jim Bridger plant. Any decision to close the mine
2 would be a long-term decision made as part of the Company's long-term fuel supply
3 strategy for the Jim Bridger power plant. Once the Company has made the decision
4 to maintain the Bridger mine as part of the fuel supply strategy, the Company must
5 incur the fixed costs to have the mine available to operate.

6 **Q. Has the Company presented its fuel supply strategy for the Jim Bridger plant to**
7 **the Commission and made it available for review by the Sierra Club and other**
8 **parties?**

9 A. Yes. As testified in detail by PacifiCorp witness Mr. Dana Ralston, the fuel supply
10 strategy for the Jim Bridger plant, including the alternatives for operating the Bridger
11 Coal Company mine have been repeatedly presented to the Commission and other
12 parties and reviewed for prudence. Additionally, PacifiCorp has continuously
13 provided information to the Commission to review the Jim Bridger fuel strategy and
14 the continued operations at the Bridger Coal Company mine.

15 **Q. Did Mr. Burgess present any testimony as to whether the fuel supply strategy for**
16 **Jim Bridger is imprudent?**

17 A. No. He simply proposes a disallowance from the 2021 TAM for the costs of the
18 Bridger Coal Company mine to the extent that the average Jim Bridger fuel costs are
19 above the projected average fuel costs for the Company's gas-fired power plants.
20 This is not an appropriate adjustment.

21 **Q. What is the basis for the adjustment proposed by Mr. Burgess for the**
22 **Huntington power plant?**

23 A. Mr. Burgess assumes that the entire amount of the projected 2021 generation for the

1 Huntington plant ([REDACTED]) would
2 be replaced by the average projected cost of natural gas generation [REDACTED]
3 for a cost savings of [REDACTED].

4 **Q. Doesn't the Huntington plant have a long-term coal supply contract with a**
5 **minimum take provision?**

6 A. Yes. In 2014, PacifiCorp signed a long-term coal supply contract with Wolverine
7 Fuels that contains an annual minimum coal purchase amount of [REDACTED] tons per
8 year through 2029 to replace the coal supply from the closed Deer Creek mine. This
9 coal supply contract decision was reviewed by the Commission in docket UM 1712 in
10 2015.

11 **Q. How does Mr. Burgess explain his opinion that the minimum take provision in**
12 **the Huntington coal supply agreement (CSA) does not affect the ability to**
13 **replace this plant's generation with other lower-cost generation sources without**
14 **incurring any take-or-pay penalty costs?**

15 A. Mr. Burgess opined that "the Huntington CSA also contains a provision [REDACTED]
16 [REDACTED]"¹⁷

17 **Q. Is Mr. Burgess correct in this opinion?**

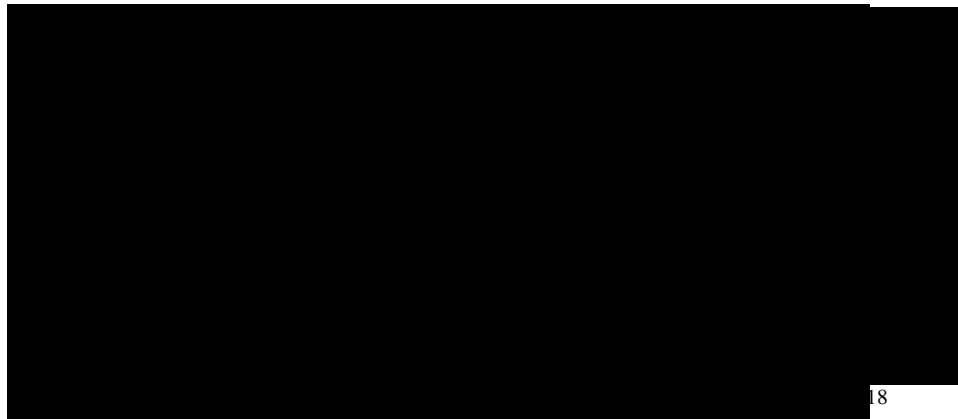
18 A. No. Mr. Burgess' misleading implies that the Company has the option to [REDACTED]
19 [REDACTED]
20 [REDACTED] This is false. The

21 [REDACTED]
22 [REDACTED]

¹⁷ Sierra Club/100, Burgess/72.

REDACTEDPAC/600
Schwartz/27

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14 **Q. Does this provision allow the Company to** [REDACTED]
15 **Huntington CSA simply because it could replace the generation with lower-cost**
16 **resources?**

17 **A. No.** [REDACTED]
18 [REDACTED]
19 [REDACTED]. Mr. Burgess has no basis for
20 his assertion that the [REDACTED]
21 [REDACTED].

22 **Q. Which power plants account for the 2021 TAM adjustment recommended by**
23 **Mr. Burgess due to exclusion of “long-term fixed costs (such as multi-year coal**
24 **contracts with minimum take provisions) should not be recovered through**
25 **annual fuel adjusters like the TAM”?**¹⁹

26 **A. Mr. Burgess cites coal supply contracts with Black Butte Coal Company for the Jim**
27 **Bridger plant and Westmoreland Mining for the Colstrip plant as costs that should be**

¹⁸ Huntington Plant CSA with Wolverine Fuels, LLC, Article VIII.

¹⁹ Sierra Club/100, Burgess/75.

1 excluded from the 2021 TAM.

2 **Q. How does Mr. Burgess calculate the amount of money that should be excluded**
3 **from the 2021 TAM under these two coal supply contracts?**

4 A. Mr. Burgess recommends excluding *the entire amount* of the projected fuel cost for
5 these contracts from the 2021 TAM, treating the fuel expenses for these two coal
6 supply contracts different from all other fuel expenses. Under this approach, the 2021
7 TAM would no longer include all of the Company's fuel costs for power supply.
8 This recommendation accounts for the large majority of the amount of the adjustment
9 recommended by Mr. Burgess.

10 **Q. Why does Mr. Burgess consider it to be appropriate to exclude the costs for**
11 **these two coal supply contracts from the 2021 TAM but no other coal supply**
12 **contracts?**

13 A. Mr. Burgess testified "I recognize that some of the coal supply agreements with
14 minimum take provisions have been in effect for many years (e.g. Naughton), and
15 that while those contractual decisions may not have been thoroughly reviewed by the
16 Commission at the time they were executed, it may be difficult to evaluate those
17 contractual decisions for prudence at this late stage."²⁰ Mr. Burgess has
18 acknowledged that it would not be appropriate for the Commission to exclude the
19 costs of a long-term coal contract from the 2021 TAM that it has already reviewed at
20 the time it was executed. However, Mr. Burgess testified that there are "contracts
21 containing minimum take provisions that have been executed by PacifiCorp very

²⁰ Sierra Club/100, Burgess/76.

1 recently and that I believe should be subject to this exclusion.”²¹ The two contracts
2 that Mr. Burgess testified should be excluded from the 2021 TAM are the Colstrip
3 (Westmoreland) and Jim Bridger (Black Butte) contracts.

4 **Q. Has the Commission and Sierra Club previously had the opportunity to review**
5 **the prudence of the decision to enter into the Black Butte coal supply contract in**
6 **2018?**

7 A. Yes. As testified by Mr. Ralston, the Commission and other parties reviewed the fuel
8 supply strategy for the Jim Bridger plant in the 2018 TAM, including the decision to
9 enter into a new coal supply contract with Black Butte with a minimum take
10 obligation. Having reviewed and approved PacifiCorp’s strategy to enter in to this
11 contract,²² it would not be appropriate for the Commission now to exclude these costs
12 from the 2021 TAM.

13 **Q. Why does Mr. Burgess recommend excluding the costs of the new Colstrip coal**
14 **supply contract from the 2021 TAM?**

15 A. Mr. Burgess simply recommends that “these types fixed fuel costs be excluded from
16 the TAM for accounting purposes and instead allow PacifiCorp to request their
17 recovery through a more appropriate venue, such as a general rate case, if it chooses
18 to do so.”²³

²¹ *Id.*

²² Order. No. 17-444 at 13-14.

²³ Sierra Club/100, Burgess/75.

REDACTED

1 **Q. How does the projected fuel cost of generation for the Colstrip plant under this**
2 **new CSA in the 2021 TAM compare to the “benchmark” average fuel cost for**
3 **the Company’s gas resources used by Mr. Burgess for calculating the exclusion**
4 **of generation costs from the TAM?**

5 A. The projected fuel cost of generation for the new Colstrip contract in the 2021 TAM
6 is [REDACTED] per MWh, much less than Mr. Burgess’ proposed “benchmark” fuel cost of
7 [REDACTED] per MWh.

8 **Q. If Mr. Burgess had used the same methodology for the Colstrip plant as he used**
9 **for the other PacifiCorp coal units, what would the impact have been on the**
10 **2021 TAM?**

11 A. Because the Colstrip fuel costs are lower than the “benchmark” recommended by Mr.
12 Burgess, his methodology would cause the 2021 TAM to be *increased* by \$ [REDACTED]
13 million, rather than reduced by \$ [REDACTED] million.

14 **Q. Did the Company provide the new Colstrip coal supply agreement to the**
15 **Commission and other parties for review in this case?**

16 A. Yes.

17 **Q. Did Mr. Burgess offer an opinion that the Company was imprudent to enter into**
18 **the new coal supply agreement for the Colstrip plant in the case?**

19 A. No.

20 **Q. Did the Commission Staff review the new Colstrip contract in this case?**

21 A. Yes.

1 **Q. Did the Commission staff find any terms of the new Colstrip contract to be**
2 **imprudent?**

3 A. No. As testified by Ms. Soldavini: “Though it is important to note Staff conducted a
4 relatively brief review in a virtual setting, in Staff’s review of the coal supply
5 agreement, it found no terms in the agreement which would lead Staff to conclude the
6 coal supply agreement is imprudent. Staff notes that the contract appears to provide
7 sufficient flexibility for PacifiCorp to adjust its obligations under the contract in
8 response to evolving circumstances.”²⁴

9 **VIII. RENEGOTIATION PROVISIONS IN PACIFICORP’S COAL**
10 **SUPPLY CONTRACTS**

11 **Q. Mr. Burgess recommended that the Commission “Direct PacifiCorp to review its**
12 **coal contracts with renegotiation provisions.”²⁵ What is the basis of this**
13 **recommendation?**

14 A. Mr. Burgess testified that he is “aware of other PacifiCorp coal supply agreements
15 that have provisions that would allow them to be renegotiated...”²⁶ He listed three
16 contracts with “such provisions”:

- 17 ○ Naughton Plant CSA– PacifiCorp & Kemmerer Operations, LLC
- 18 Article 3.1 Environmental Response
- 19 ○ Huntington Plant CSA– PacifiCorp & Wolverine Fuels, LLC
- 20 Article VIII Environmental Regulations
- 21 ○ Colstrip Plant CSA – PacifiCorp & Westmoreland Rosebud Mining, LLC
- 22 Article 8.1 Changes in Applicable Law

²⁴ Staff/300, Solavini/14.

²⁵ Sierra Club/100, Burgess/4.

²⁶ Sierra Club/100, Burgess/27.

1 **Q. In your opinion, do these provisions allow these CSA to be “renegotiated” by the**
2 **Company?**

3 A. No. These provisions in a long-term CSA are known as “change in law” or “change
4 in environmental regulation” provisions. They provide for the relief of the
5 Company’s performance obligations only under the situation where there is a change
6 in laws or regulations that restricts the Company’s ability to perform under the
7 contract. It is highly misleading for Mr. Burgess to imply that the Company has the
8 ability to compel the supplier renegotiate these contracts for economic reasons under
9 these provisions.

10 **Q. What is required for the Company to use these provisions to renegotiate the**
11 **contracts?**

12 A. There would need to be an event satisfying the precondition that a change in
13 environmental laws or regulations, as described in the contract provisions, has
14 occurred. Sierra Club urges PacifiCorp to renegotiate the contracts for purely
15 economic reasons, which is not covered by these provisions.

16 **Q. Does this conclude your reply testimony?**

17 A. Yes.

Docket No. UE 375
Exhibit PAC/601
Witness: Seth Schwartz

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of Seth Schwartz

Seth Schwartz' Resume

June 2020

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° to 350°", Geochimica et Cosmochimica Acta (42)1427-1437, 1978.

REDACTED

Docket No. UE 375

Exhibit PAC/700

Witness: Dana M. Ralston

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

REDACTED

Reply Testimony of Dana M. Ralston

June 2020

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

4 A. Yes.

5 **I. PURPOSE AND SUMMARY OF TESTIMONY**

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

7 A. I respond to the opening testimony of Mr. Ed Burgess, filed on behalf of Sierra
8 Club, challenging PacifiCorp's coal fuel expenditures. I also address an issue
9 raised in the opening testimony of Mr. Bob Jenks, on behalf of the Oregon
10 Citizens' Utility Board (CUB), regarding costs associated with the retirement of
11 Naughton Unit 3 as a coal generator, and an adjustment related to Bridger Coal
12 Company (BCC) depreciation and reclamation expense raised in the opening
13 testimony of Bradley Mullins, on behalf of the Alliance of Western Energy
14 Consumers (AWEC).

15 **Q. Please summarize your testimony.**

16 A. My testimony:

- 17 • Provides coal costs for the Transition Adjustment Mechanism (TAM) reply
18 update,
- 19 • Provides relevant history and Public Utility Commission of Oregon
20 (Commission) precedent regarding PacifiCorp's fueling strategy for its coal
21 plants,
- 22 • Reviews PacifiCorp's strategy for fueling its coal plants and demonstrates the
23 prudence of the fuel expenditures included in this case,

- 1 • Refutes Sierra Club’s claim that minimum tonnage provisions harm customers
2 and discusses how generation levels and fuel supply needs are determined,
- 3 • Defines dispatch tier cost as incremental cost, the cost associated with
4 producing an additional megawatt, and explains why the use of incremental
5 costs instead of average costs for plant dispatch is beneficial to customers,
- 6 • Rejects Sierra Club’s recommendations as unjustified and unprecedented,
- 7 • Refutes CUB’s position that PacifiCorp was imprudent in negotiating the
8 Naughton coal supply agreement (CSA) in 2010 and should therefore share a
9 portion of the costs associated with the retirement of Naughton Unit 3, and
- 10 • Rejects AWEC’s recommendation on the treatment of BCC costs as
11 unwarranted.

12 II. TAM REPLY UPDATE TO COAL COSTS

13 **Q. Please describe the overall impact to PacifiCorp’s coal fuel expense in the TAM**
14 **reply update.**

15 A. Under the TAM Guidelines, PacifiCorp updates coal costs in the reply update to
16 reflect actual and projected changes in coal and transportation contracts. Coal fuel
17 expense for the 2021 TAM has decreased from \$612.7 million in the initial filing to
18 \$577.5 million in the reply update, a decrease of \$35.2 million on a total-company
19 basis.¹ Lower coal volumes decreased coal fuel expense by \$11.4 million, while the
20 updated prices reduced coal fuel expense by \$23.8 million.

¹ All references to coal costs and revenues in this testimony are on a total-company basis, unless noted otherwise.

1 **Q. Please identify the primary drivers of the \$23.8 million fuel expense reduction**
2 **due to lower coal prices in the reply update compared to the initial filing.**

3 A. Affiliated captive mine unit cost reductions result in a [REDACTED] fuel expense
4 decrease, related to additional supplemental coal delivered by BCC to Jim Bridger
5 plant as shown in Confidential Table 1 below. As reflected in the reply update,
6 PacifiCorp exercised a clause in the CSA with Black Butte to defer [REDACTED] from
7 being purchased in 2021 to 2022. As a result, PacifiCorp was able to add an
8 additional [REDACTED] tons of supplemental coal deliveries from BCC above the base
9 mine plan. Because the incremental BCC coal is produced at a lower unit cost than
10 the base mine plan coal, the total weighted-average unit cost is reduced by delivering
11 additional coal resulting in a decrease to fuel expense.

12 **Confidential Table 1: Coal and Transportation Contract Price Variance**

Plant	Contract	Millions (\$)
Naughton	Kemmerer Coal	
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)		

13 Third-party coal purchases and transportation unit cost decreases result in a
14 [REDACTED] fuel expense reduction, primarily due to a [REDACTED] reduction to

1 coal costs at the Hunter plant. For this update, the pricing for Hunter coal costs is
2 based upon a market forward price for Utah coal, as published in Energy Ventures
3 Analysis Fuelcast in May 2020 and estimated pricing from a pending request for
4 proposals. An additional [REDACTED] decrease in coal costs at the Hunter plant is
5 attributed to the removal of the Energy West pension costs from coal costs. The
6 removal of the Energy West pension costs is also the basis for the [REDACTED]
7 decrease at the Huntington plant. Consistent with CUB's recommendation in this
8 case, PacifiCorp proposes to include these costs in base rates in its pending general
9 rate case, docket UE 374.²

10 An additional [REDACTED] decrease in fuel cost is due to lower contract
11 indices and diesel fuel costs at the Naughton, Wyodak, and Colstrip plants. There are
12 also small reductions for Hayden and Jim Bridger rail costs for lower diesel fuel
13 costs. These savings are partially offset by [REDACTED] in higher fuel prices at the
14 Jim Bridger plant for the reduced volume of Black Butte coal purchases in the test
15 period and [REDACTED] for an increase to the market price for the spot coal purchases
16 for the Dave Johnston plant.

17 **III. BACKGROUND ON PAST FUEL SUPPLY ISSUES IN THE TAM**

18 **Q. Sierra Club acknowledges that the TAM involves "substantial review" of**
19 **PacifiCorp's fuel supply costs, but contends that this review has not focused on**
20 **coal supply contracts or coal plant dispatch.³ Is this true?**

21 **A.** No. The Commission has regularly reviewed coal-related issues in the TAM,
22 including issues related to coal supply contracts and coal plant dispatch. This is

² CUB/100, Jenks/9-12.

³ Sierra Club/100, Burgess/9-10.

1 particularly true with respect to the Jim Bridger plant, PacifiCorp's largest coal plant
2 and the central focus of Sierra Club's coal cost adjustment in this case.

3 Approximately \$ [REDACTED] million of Sierra Club's \$ [REDACTED] million adjustment—more than
4 [REDACTED] percent—is related to coal supply at the Jim Bridger plant. Issues regarding
5 PacifiCorp's fueling strategy for the Jim Bridger plant have been raised multiple
6 times over the years, including in the dockets UE 264 (2014 TAM), UE 307
7 (2017 TAM), UE 323 (2018 TAM), UE 339 (2019 TAM), and UE 356 (2020 TAM),
8 and the Commission has repeatedly affirmed the reasonableness of the Company's
9 strategy. Issues regarding coal contracts, coal dispatch, and coal plant cycling were
10 addressed in the 2017 TAM, the 2018 TAM and the 2019 TAM. Sierra Club
11 completely ignores all of this precedent, much of which is directly adverse to its
12 proposed adjustments.

13 **Q. Please describe what occurred in the 2014 TAM proceeding.**

14 A. In the 2014 TAM, the Industrial Customers of Northwest Utilities (ICNU), the
15 predecessor to AWEC, proposed a disallowance under OAR 860-277-0048, the
16 Commission's lower of cost or market rule for affiliates. ICNU claimed that third-
17 party coal from the Black Butte mine was lower priced than coal from BCC mine, so
18 the BCC coal should be repriced based on the Black Butte contract.

19 The Commission rejected this adjustment, approving PacifiCorp's fueling
20 strategy for the Jim Bridger plant as "fair, just and reasonable." Specifically, the
21 Commission found there was no available lower-cost market alternative to replace
22 BCC coal. The Commission was not persuaded that Black Butte coal would be

1 available in the excess capacity required or that it would be less expensive than the
2 BCC contract price for the period in question.⁴

3 **Q. What standard did the Commission apply in evaluating BCC coal costs in the**
4 **2014 TAM?**

5 A. The Commission adhered to its practice of evaluating BCC coal costs for whether
6 they were objectively reasonable. The Commission found those costs reasonable in
7 the 2014 TAM because while the BCC and Black Butte prices had fluctuated over the
8 years, they had remained relatively stable when viewed over the long term. In
9 addition, the Commission found there was scarce availability for lower-cost market
10 alternatives to BCC coal.

11 At the suggestion of PacifiCorp, Commission Staff (Staff) and CUB, the
12 Commission directed the Company to prepare “a periodic fuel supply plan that
13 compares affiliate mine fuel supply to other alternative fuel supply options, including
14 market alternatives.”⁵

15 **Q. Please describe what occurred in the 2017 TAM proceeding.**

16 A. In the 2017 TAM, ICNU and Staff challenged Jim Bridger fuel costs on the basis that
17 BCC coal costs were higher than market alternatives, albeit this time with reference to
18 coal from the Powder River Basin rather than the Black Butte mine. Staff argued the
19 Company was imprudent in failing to consider market alternatives, while ICNU
20 revived its arguments from the 2014 TAM regarding the lower of cost or market rule.

⁴ *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).

⁵ *Id.* at 7.

1 The Commission rejected both sets of arguments, reaffirming the reasonableness of
2 PacifiCorp's fueling strategy.⁶

3 **Q. Did the Commission make any other relevant rulings with respect to Jim**
4 **Bridger fuel supply?**

5 A. Yes. The Commission directed the Company to delay filing its long-term fuel supply
6 plan for the Jim Bridger plant, and instead meet informally with the parties to discuss
7 the information needed to provide a meaningful evaluation of the long-term fuel
8 supply plan for the Jim Bridger plant in future TAM proceedings.⁷

9 **Q. Did parties raise other coal-related issues in the 2017 TAM?**

10 A. Yes. CUB challenged the prudence of minimum-take provisions in three of the
11 Company's coal contracts, the Black Butte contract for Jim Bridger, and the
12 Huntington and Dave Johnston coal contracts. The Commission rejected CUB's
13 proposed disallowance, finding that minimum take provisions are standard in coal
14 supply contracts and that the alternative would be for the Company to rely on the spot
15 market for coal, which would create both supply and price risks. Additionally, the
16 Commission observed that two of the three contracts challenged by CUB were short-
17 term.⁸

18 **Q. Did any other party raise issues with respect to minimum take provisions in the**
19 **2017 TAM?**

20 A. Yes. Staff also challenged the manner in which the Company accounted for the
21 effects of minimum take provisions in its Generation and Regulation Initiative

⁶ *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).

⁷ *Id.* at 7.

⁸ Order No. 16-482 at 9.

1 Decision Tools (GRID) modeling. The Commission rejected this challenge observing
2 that the Company's practice of iteratively adjusting GRID to model minimum take
3 provisions was consistent with PacifiCorp's practice in prior TAM proceedings.⁹

4 **Q. Please describe what occurred in the 2018 TAM proceeding.**

5 A. In the 2018 TAM, PacifiCorp reported on the two workshops held on Jim Bridger
6 fueling strategy after the conclusion of the 2017 TAM. The Company also reported
7 that it had identified different fuel plan scenarios, selected the least-cost, least-risk
8 option, and was on track to complete its long-term fuel plan by the target date of
9 December 2017. The Commission approved PacifiCorp's plans to finalize the long-
10 term fuel plan and directed that the long-term fuel plan be attached to testimony in the
11 2019 TAM.

12 **Q. In the 2018 TAM, did the Commission also review the Company's near-term**
13 **fuel strategy for the Jim Bridger plant, including execution of the current Black**
14 **Butte coal supply contract?**

15 A. Yes. Because the Black Butte CSA was set to expire at the end of 2017, negotiations
16 for a new contract were ongoing during the 2018 TAM. I presented the strategy to
17 procure approximately one-third of Jim Bridger's coal supply from the Black Butte
18 mine for a term of three-to-four years in my testimony in the 2018 TAM and in the
19 long-term fuel plan workshops. In its final order in the 2018 TAM, the Commission
20 approved PacifiCorp's near-term fuel strategy for the Jim Bridger plant, which
21 included the new Black Butte contract.¹⁰

⁹ *Id.* at 10-11.

¹⁰ *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No, UE 323, Order No. 17-444, at 13-14 (Nov. 1, 2017).

1 **Q. Did Staff raise coal issues in the 2018 TAM?**

2 A. Yes. As discussed in more detail in the testimony of Mr. David G. Webb, Staff
3 proposed an adjustment to reflect economic cycling at its coal plants. The
4 Commission declined to impose any adjustments related to PacifiCorp's forecasted
5 coal plant dispatch, finding that the Company's GRID modeling reflected historical,
6 normalized practices. The Commission directed, however, that the parties add
7 economic cycling modeling to the proposed coal workshop (described below) and
8 that PacifiCorp report at a subsequent public meeting on proposals for incorporating
9 economic cycling into dispatch modeling.¹¹ Staff also addressed an issue related to
10 coal inventories, which the Commission resolved by directing PacifiCorp to file a
11 report in the 2019 TAM updating and expanding its 2010 fleetwide coal inventory
12 policies and procedures.

13 **Q. Did Sierra Club intervene in the 2018 TAM for the first time and raise**
14 **challenges to PacifiCorp's coal supply contracts?**

15 A. Yes. Sierra Club proposed an adjustment related to the Naughton CSA, which it later
16 withdrew.¹² Sierra Club also recommended that the Commission direct PacifiCorp to
17 refrain from entering into new coal supply contracts with minimum-take provisions
18 because of dispatch issues. Ultimately, Sierra Club and PacifiCorp came to an
19 understanding, and these issues were withdrawn based on an agreement to conduct a
20 workshop to address the following issues:¹³

- 21 • PacifiCorp's process by which the terms and conditions of long-term coal

¹¹ Order. No. 17-444 at 10-11.

¹² See *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Sierra Club/200, Vitolo/2 (Aug. 2, 2017).

¹³ See Order No. 17-444 at 11.

1 contracts are developed, negotiated and approved, and how the Company
2 accounts for plant fuel requirements when negotiating long-term contracts
3 or coal mine investment decisions.

- 4 • PacifiCorp's process for managing risk in long-term coal contracts related
5 to: (a) price; (b) contract length; (c) minimum take provisions; (d) liquidated
6 damages; and (e) changing electricity market conditions.
- 7 • How long-term coal contract provisions impact dispatch decisions in GRID,
8 commitment decisions, and long-term system modeling decisions.
- 9 • How (a) long-term coal contracts, (b) fuel transportation contracts, and (c)
10 spot market coal fuel purchases are each reviewed before the Commission.
- 11 • The potential development of a method to reflect variable operation and
12 maintenance (O&M) in NPC, including classification of which O&M costs
13 should be treated as variable and the treatment of variable O&M in rates.
- 14 • Coal plant economic cycling.

15 **Q. When did PacifiCorp convene this workshop?**

16 A. PacifiCorp convened the workshop on February 23, 2018. PacifiCorp reported on the
17 results of the workshop at the Commission's March 13, 2018 public meeting.

18 **Q. Please describe the Company's filing in the 2019 TAM proceeding.**

19 A. In the 2019 TAM, the Company submitted testimony summarizing the results of
20 PacifiCorp's February 23, 2018 workshop on coal supply contracts and dispatch
21 issues and included the presentation from the workshop as an exhibit to my
22 testimony.¹⁴ In my testimony, I also included PacifiCorp's long-term fuel plan for the

¹⁴ Docket No. UE 339, Exhibit PAC/201.

1 Jim Bridger plant (2018 Fuel Plan),¹⁵ and provided details on the new Black Butte
2 contract. Consistent with PacifiCorp's near-term fuel strategy approved in the
3 2018 TAM and outlined in the 2018 Fuel Plan, the Black Butte contract was executed
4 on February 6, 2018, with a 44-month term, beginning May 1, 2018, and ending
5 December 31, 2021. PacifiCorp has the option under the contract to extend the term
6 an additional four months, through April 30, 2022, with no change in volume or price.

7 **Q. What happened in the 2019 TAM?**

8 A. Sierra Club did not intervene in the case, and no party objected to the final Black
9 Butte contract. The Commission approved a stipulation in which the parties agreed
10 PacifiCorp would complete additional analysis with respect to the 2018 Fuel Plan.
11 Specifically, the Company agreed to update its analysis using 2030 rather than 2037
12 as an end date for the useful life of the plant, for the purpose of evaluating whether
13 the Jim Bridger fueling strategy is reasonable if the plant life is shortened for Senate
14 Bill (SB) 1547 compliance. The parties further agreed to set parameters for this
15 analysis and to include the analysis in the 2020 TAM if it modifies the 2018 Fuel
16 Plan.¹⁶ In addition, the parties agreed to PacifiCorp's proposals to model economic
17 cycling of coal plants and to include variable O&M in modeling coal dispatch in
18 GRID.

19 **Q. Please describe the Company's filing in the 2020 TAM proceeding.**

20 A. In my testimony in the 2020 TAM, I included an update to PacifiCorp's 2018 Fuel
21 Plan that reflected a shortened plant life of 2030 instead of 2037.¹⁷ This alternative

¹⁵ Docket No. UE 339, Exhibit PAC/204.

¹⁶ *In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, at 4 (Oct. 26, 2018).

¹⁷ Docket No. UE 339, Exhibit PAC/201.

1 analysis resulted in the same fuel plan being selected as the least-cost, least-risk
2 option, validating the reasonableness of the Company's Jim Bridger fueling strategy.

3 I also provided background on PacifiCorp's negotiations for a new coal
4 supply contract at the Colstrip plant to replace the contract expiring at the end of
5 2019.

6 **Q. Please describe what occurred in the 2020 TAM proceeding.**

7 A. No party objected to the revised Jim Bridger fuel plan.¹⁸ With respect to the new
8 Colstrip contract, Staff noted that it had been working closely together with
9 PacifiCorp to stay apprised of developments in the highly confidential contract
10 negotiations. Staff also noted that it retained the ability to review the final contract
11 for prudence, including in the 2021 TAM if the contract was finalized after the close
12 of the record in the 2020 TAM.¹⁹

13 **Q. How was the 2020 TAM resolved?**

14 A. The Commission approved an all-party stipulation in which the only coal-related
15 provision was an agreement to hold a workshop on Jim Bridger depreciation issues.
16 In its order, the Commission noted that it had closely tracked Jim Bridger costs for
17 several years and directed PacifiCorp to update its Jim Bridger fuel plan, given the
18 earlier end-of-life dates in its 2019 IRP. Specifically, the Commission asked
19 PacifiCorp to explain how the Company is planning ahead with more flexible fueling
20 arrangements to avoid minimum take penalties such as those that occurred at the
21 Naughton coal facility in the 2020 TAM.²⁰

¹⁸ Sierra Club was not an intervenor in the 2020 TAM proceeding.

¹⁹ Docket No. UE 356, Staff/200, Soldavini/14.

²⁰ *In the Matter of PacifiCorp, dba Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351, at 8 (Oct. 30, 2019).

1 The Commission subsequently amended its order, at PacifiCorp’s request, to
2 allow for testimony and a Commission workshop in the 2021 TAM, rather than
3 developing an updated fuel plan. The Company committed to providing information
4 at the Commission workshop on “minimum take penalties, and the flexibility of the
5 fueling arrangements with company-owned and third-party coal suppliers in light of
6 earlier end of life dates.”²¹

7 **Q. Please explain how PacifiCorp complied with these orders.**

8 A. PacifiCorp held a workshop with the parties on BCC depreciation. My direct
9 testimony in this case addresses PacifiCorp’s plan for avoiding minimum take
10 penalties at the Jim Bridger plant, noting that the Black Butte contract minimums
11 cover only a portion of the coal supply for the plant and that the coal supply from
12 BCC offers more ability to flex coal supply to adjust to changing generation forecasts.

13 **Q. Did PacifiCorp participate in a Commission workshop to address these issues in**
14 **May 2020?**

15 A. Yes. In advance of the workshop, the Commission issued an agenda with several
16 questions for discussion, each of which I respond to below. I have provided the
17 presentation I made at the workshop as Confidential Exhibit PAC/701, which also
18 addresses these questions.

19 **Q. Please discuss the contract length, term, and forward negotiation opportunities**
20 **for Naughton coal supply, explaining the current level of coal contracted and**
21 **whether minimum take opportunities will be avoidable going forward.**

22 A. The future CSA will be a shorter term (up to four years) taking into account the

²¹ Docket No. UE 356, Order No. 20-023, at 1-2 (Jan. 22, 2020).

1 closure dates for Naughton Units 1 and 2. The other factors that will be taken into
2 account when evaluating any future agreement will be market opportunities, volume
3 flexibility, delivered pricing, coal quality considerations and appropriate take-or-pay
4 and/or liquidated damages provisions based on the forecasted generation
5 requirements.

6 **Q. Please provide the expected near term delivery in annual tons for all Jim**
7 **Bridger coal sources.**

8 A. For the 2021 TAM, the Jim Bridger plant will receive [REDACTED] (PacifiCorp
9 share). This is comprised of [REDACTED] from BCC and [REDACTED] from
10 Black Butte.

11 **Q. What are the minimum take levels in the Company's CSAs at each plant, and**
12 **how do these minimum take levels intersect with or adapt to changes in capacity**
13 **factors at these plants?**

14 A. As presented in the workshop, Confidential Table 2 shows the contract minimums
15 and forecasted deliveries for each of the current contracts.

1 **Confidential Table 2: Contract Minimums – Coal Supply Agreements**

Plant	Coal Mine	Minimum Deliveries	Forecast Deliveries	Minimum %
Colstrip	Rosebud			
Craig	Trapper			
Dave Johnston	Coal Creek			
Dave Johnston	Caballo			
Dave Johnston Total				
Hayden	Twentymile			
Hunter	Unknown			
Huntington	Various			
Jim Bridger	Black Butte			
Jim Bridger	Bridger			
Jim Bridger Total				
Naughton	Kemmerer			
Wyodak	Wyodak			
Note: Deliveries are in tons and represent PacifiCorp share				

2 **Q. Last summer PacifiCorp applied to the Wyoming Department of Environmental**
3 **Quality (DEQ) to lower plant-wide nitrogen oxides (NOx) and sulfur dioxide**
4 **(SO₂) emissions in lieu of Selective Catalytic Reduction (SCR) on Jim Bridger**
5 **Units 1 and 2. Did the Wyoming DEQ grant the application and set a plant wide**
6 **limit of 8.62 million tons of coal per year (a 76 percent average capacity factor),**
7 **effective January 1, 2022, and will this permit limit Jim Bridger operations in**
8 **any way?**

9 **A. In February of 2019, PacifiCorp submitted an application to Wyoming DEQ and**
10 **proposed that the agency implement more stringent plant-wide NOx and SO₂**
11 **emission limits in lieu of the requirement to install SCR systems on Jim Bridger Units**
12 **1 and 2. The application did not propose a capacity factor limit or a coal through put**
13 **limit on the facility; however, the application used a calculated effective annual**

1 average capacity of 76.3 percent to evaluate other environmental impacts of the
2 proposal, including: changes in potential coal throughput (8.62M tons/yr); decreases
3 in potential carbon dioxide emissions; decreases in coal combustion residuals waste
4 streams; water use; etc. Wyoming DEQ granted final approval of the application in
5 May of 2020, and submitted it to the Environmental Protection Agency (EPA) Region
6 8 for federal review and approval, which will include a public comment process. If
7 approved by EPA, the proposed limits would result in a restriction on the plant's
8 maximum plant-wide potential to emit NO_x and SO₂ on a monthly and annual basis.
9 The plant's current operations and emissions are not analyzed under the application,
10 because the analysis focuses on what the facility could emit, rather than what it does
11 emit. As presented in the workshop on May 12, 2020, PacifiCorp's projected future
12 emissions, which are based on forecasted generation, are expected to remain lower
13 than the new approved limits.

14 **Q. The current Black Butte coal contract expires at the end of 2021. How will a**
15 **new contract accommodate changes to the plant's operations?**

16 A. Future Black Butte agreements will be short-term in duration (less than five years),
17 rely on PacifiCorp's fueling strategy, and use the generation forecasting process
18 described below and in Mr. Doug Young's testimony.

19 **Q. The coal contract for Hunter ends in 2020. What elements of flexibility will be**
20 **incorporated in any new coal supply contract?**

21 A. Any new CSA for Hunter will follow PacifiCorp's fueling strategy that focuses on a
22 shorter term, coal quality, pricing, volume flexibility, environmental response or

1 change of law provisions, and take or pay/liquidated damage provisions that are
2 appropriate.

3 **Q. Please provide an update on the current status of Westmoreland's bankruptcy**
4 **proceeding and how PacifiCorp is managing risk in its contracts for Colstrip**
5 **and Naughton fueling.**

6 A. PacifiCorp was impacted at two locations, the Naughton and Colstrip plants. The
7 Westmoreland bankruptcy was bifurcated into two bankruptcies. The Westmoreland-
8 Kemmerer Mine bankruptcy was completed in June 2019. The PacifiCorp CSA was
9 assigned to Kemmerer Operations LLC as part of the bankruptcy proceeding. This
10 agreement will expire December 31, 2021. The Westmoreland-Rosebud Mine
11 bankruptcy was completed in March 2019 and a new mining company was formed,
12 Westmoreland Rosebud Mining LLC. PacifiCorp, along with the four other Colstrip
13 owners executed a new CSA in December 2019.

14 **IV. PACIFICORP'S FUELING STRATEGY**

15 **Q. As just described, PacifiCorp has addressed coal supply issues in most TAM**
16 **proceedings since 2013. Has the Company's coal supply strategy evolved in**
17 **response to these regulatory processes and to changes in the markets?**

18 A. Yes. Most notably, to minimize risk and add flexibility to its system planning, the
19 Company's current strategy is to limit the term of its CSAs as much as practicable.
20 PacifiCorp has not executed a coal supply contract with a firm term longer than five
21 years since 2014.²² This strategy allows the Company to continually reassess its

²² In 2019, PacifiCorp entered into a CSA with Westmoreland Coal Company at the Colstrip plant. The new CSA was negotiated with the other owners at the Colstrip plant. PacifiCorp was successful in negotiating a five-year agreement, [REDACTED]

1 least-cost, least-risk resource portfolio in its Integrated Resource Plan (IRP).
2 PacifiCorp has also included environmental response or change of law provisions
3 where possible in its contracts with longer terms. The Company has used the long-
4 term fuel plan for the Jim Bridger plant to analyze and support its fueling strategy and
5 to optimize BCC operations. Finally, as discussed by PacifiCorp witness Mr. Webb,
6 the Company has included variable O&M in its dispatch decisions for coal units and
7 modeled the economic cycling of coal units.

8 **Q. Please describe PacifiCorp's approach to fueling its coal generation plants.**

9 A PacifiCorp's goal in fuel planning is to secure the least-cost, least-risk fuel supply for
10 customers. The Company begins with an estimate of the annual and future generation
11 forecasts of the plants. The Company then develops fuel volume, pricing and
12 sourcing assumptions, transportation costs, and if necessary, operating and capital
13 costs for the plants. The costs from all sources are combined and evaluated to create
14 the least-cost, least-risk fueling plan for PacifiCorp's coal plants.

15 **Q. How does PacifiCorp develop its estimates of annual generation forecasts?**

16 A. As described by PacifiCorp witness Mr. Young, PacifiCorp prepares generation
17 forecasts as a part of its budget and planning forecasts relying on the most accurate
18 and up-to-date information available. To prepare the generation forecast estimates,
19 the Company considers many factors including historical usage patterns, sales and
20 load forecasts, market prices, changes in available generation, and reliability
21 requirements. As Sierra Club notes, coal generation volumes decreased in the

1 original 2021 TAM filing by approximately 15 percent.²³ Coal generation volumes
2 decreased an additional 2 percent in the TAM update for a total of 17 percent.

3 **Q. Does PacifiCorp use net power costs modeled in the TAM or other regulatory**
4 **filings as the starting point for contract negotiations?**

5 A. No. Generation forecasts are developed to ensure that adequate resources are
6 available to meet PacifiCorp's forecasted area load demand as well as any
7 opportunities for off-system wholesale sales that could benefit customers. Generation
8 is modeled through an iterative process based on existing resources and contracts,
9 forecasted market pricing, and projected load requirements. As model results are
10 obtained, adjustments are made and then remodeled. This process may occur several
11 times. Mr. Young's testimony explains this process in greater detail. Net power costs
12 are the end result of the process, not the starting point. New contracts are negotiated
13 to meet future generation needs.

14 **Q. Please explain PacifiCorp's general approach to obtaining its CSAs.**

15 A. PacifiCorp's third-party fuel contracts are negotiated to meet its generation forecasts
16 in the least cost, least risk manner. The Company's process in developing and
17 negotiating contracts considers and evaluates factors like term, price, volume, plant
18 location/coal region, coal supply options, coal transportation options, and coal
19 quality.

20 **Q. Please describe the challenges associated with negotiating CSAs.**

21 A. As explained by PacifiCorp's expert witness Mr. Seth Schwartz, unlike other
22 commodities, there is no central, liquid market for coal supply. Coal quality

²³ Sierra Club/100, Burgess/15.

1 specifications vary by region, transportation costs are significant, and many coal
2 plants are located in areas where supplies are limited. Therefore, the Company must
3 consider term, price, volume, and coal quality when negotiating third-party CSAs,
4 and seek to strike the optimum balance among these factors. Negotiations for
5 bilateral CSAs are necessarily specific to the individual plant, mine or mines that can
6 serve the plant, and overall coal market.

7 **Q. Please explain how minimum take and liquidated damages provisions operate in**
8 **the Company's coal contracts.**

9 A. A minimum take, or "take-or-pay," provision generally requires the Company to
10 purchase a minimum specified amount of coal over a given time period. Similarly, a
11 liquidated damages provision requires the Company to pay a pre-determined amount
12 if it does not purchase a certain amount of coal under the agreement.

13 **Q. Are minimum take and liquidated damages provisions a standard aspect of coal**
14 **supply contracts?**

15 A. Yes. As the Commission found in the 2017 TAM, minimum take and liquidated
16 damages provisions are an essential component of virtually all CSAs and constitute
17 the consideration required to obtain favorable pricing and security of supply. Sierra
18 Club acknowledges that "minimum take provisions have traditionally been part of
19 CSAs and might be required from the seller," but it nevertheless opposes these
20 provisions.²⁴

²⁴ Sierra Club/100, Burgess/39.

1 **Q. Please explain why the Company executes coal supply contracts with minimum**
2 **take or liquidated damages provisions.**

3 A. Coal supply contracts, which necessarily include minimum take provisions, ensure
4 that a reliable supply of coal will be available to fuel the Company's plants at
5 predictable and stable prices, terms, and conditions. Absent a CSA, the Company
6 would be required to supply its plants exclusively with spot market purchases.
7 Relying exclusively on the spot market, however, is an extremely risky strategy that
8 would expose customers to substantial and unreasonable price, volume, coal quality
9 and supply risk.

10 **Q. Sierra Club claims that minimum tonnage provisions present a severe limitation**
11 **and harm customers.²⁵ Do you agree?**

12 A. No. In fact, the exact opposite is true. Minimum-take contracts significantly reduce
13 the risk associated with coal supply availability. Multi-year contracts significantly
14 reduce the risk to customers associated with market price volatility or fluctuations. It
15 is substantially more risky if the Company did not have fuel for electricity generation
16 during certain times of the year. These provisions are especially important at plants
17 like the Jim Bridger, Naughton and Colstrip plants because of the inability to receive
18 significant quantities of coal from other sources.

²⁵ Sierra Club/100, Burgess/24.

1 **Q. Sierra Club provides a table comparing per unit costs of PacifiCorp's coal**
2 **units.²⁶ Please explain why there are a wide range of coal burn expenses for**
3 **different plants.**

4 A. PacifiCorp's coal generation fleet spans a wide geographic area. The Company
5 purchases coal for 10 power plants in five western states. These plants are typically
6 limited to receiving coal by rail, truck or conveyor. Due to each plant's unique
7 location, design and transportation limitations, PacifiCorp purchases coal from mines
8 in various coal basins that have unique ownership structures and that utilize unique
9 mining methods, including: captive and third-party underground (longwall and
10 continuous miner) mines and captive and third-party surface (both truck shovel,
11 dragline and highwall) mines. At some locations a combination of these mining
12 methods is used to mine the coal. These distinct mine plans result in varied cost
13 structures at the individual mines. This dynamic results in a wide range of per unit
14 coal costs across the fleet, as can be seen in the table.

15 **Q. Sierra Club alleges the Company has overestimated the amount of economic coal**
16 **generation, the dispatch price is too low, and minimum-take quantities are too**
17 **high resulting in a "vicious cycle"²⁷ harming customers. Do you agree?**

18 A. No. Mr. Burgess fails to present any actual evidence related to specific contracts
19 showing that the Company unreasonably overestimated coal generation and set
20 minimum take levels too high at the time these contracts were negotiated. He
21 provides no analysis or evidence indicating that any of the contracts he references

²⁶ Sierra Club/100, Burgess/15, Table 2.

²⁷ Sierra Club/100, Burgess/30; 61-62.

1 were imprudent when they were executed or that a reasonable utility would rely
2 exclusively on the spot market, rather than a coal supply contract.

3 **Q. Do you agree with Sierra Club’s claim that PacifiCorp lacks incentive to achieve**
4 **the lowest-possible energy costs because it has the opportunity to recover its**
5 **costs through the TAM?**²⁸

6 A. No. As Mr. Webb also notes in his testimony, the Company has multiple, powerful
7 incentives to keep its energy costs low—including electric industry transformation,
8 increased competition, regulatory disallowances, and most importantly providing a
9 safe, low cost, and reliable source of energy to our customers. None of these are
10 offset by the possibility of recovery of a portion of its total system costs in the TAM,
11 especially given the dead bands and sharing bands in the Power Cost Adjustment
12 Mechanism which generally require PacifiCorp to absorb any under recovery of its
13 net power costs.

14 **V. INCREMENTAL COSTS**

15 **Q. Sierra Club notes that dispatch tier costs are lower than the cost tier at four**
16 **different units: Hunter, Huntington, Jim Bridger and Naughton.**²⁹ **Can you**
17 **explain why?**

18 A. Yes. For Huntington and Hunter, the dispatch tier is based upon the tier 2 price in the
19 CSAs. This is the price that it would cost PacifiCorp to purchase additional coal
20 above the minimum requirements under the CSA.

21 At the Jim Bridger plant, the dispatch tier cost represents the incremental cost

²⁸ Sierra Club/100, Burgess/19.

²⁹ Sierra Club/100, Burgess/33.

1 associated with procuring additional coal above the minimum mine plan volumes.
2 For the Jim Bridger plant, the incremental cost is derived by evaluating production
3 and cost differentials between two operating plans at BCC. BCC is a captive mining
4 operation adjacent to the plant and can adjust coal production quantities to comply
5 with reasonable changes in fuel requirements at the plant. In recent years, plant coal
6 consumption has decreased and enabled BCC to balance coal production and required
7 final reclamation activities. This ability to switch mining activities between coal
8 production and reclamation enables the mine to utilize mine equipment and mine
9 employees in a relatively efficient manner.

10 At the Naughton plant, the dispatch tier or incremental cost is based on the
11 current Tier 2 contract price until the end of the existing agreement. The Naughton
12 plant is supplied by the adjacent Kemmerer mine under a CSA through 2021. The
13 CSA calculates tier-1 and tier-2 tonnage volumes and pricing. As discussed above,
14 the CSA contains an environmental response provision to reduce the minimum annual
15 tonnage volume quantity in the event of a reduction in coal-fired generation at the
16 plant due to changes in environmental laws or rules.

17 As a result of Naughton Unit 3 discontinuing as a coal-fired resource in
18 January 2019, PacifiCorp exercised this provision and the annual minimum take-or-
19 pay quantity was reduced from [REDACTED] tons to [REDACTED] tons. In lieu of a full
20 take-or-pay payment of approximately [REDACTED] or [REDACTED] for the [REDACTED]
21 tons below [REDACTED], an environmental shortfall payment of only [REDACTED] or
22 [REDACTED], approximately [REDACTED] of the purchase price, will be owed in 2020

1 related to [REDACTED] shortfall tons on deliveries of [REDACTED] tons in the 2020
2 forecast period.

3 **Q. Please discuss the Naughton plant capacity factor.**

4 A. As stated above, with the closure of Naughton Unit 3, the remaining two units are run
5 at a capacity factor to meet the contractual obligation of [REDACTED] tons. This
6 contract was negotiated in 2010 and will expire at the end of 2021.

7 **Q. Do you agree with Mr. Burgess' testimony that inputs for specific units are too
8 low in the GRID model, leading to excessive dispatch?³⁰**

9 A. No. The inputs to the GRID are fully consistent with basic incremental or marginal
10 cost theories widely accepted by regulators, academia, and businesses in general.

11 **Q. Do you agree with Mr. Burgess' testimony that economic theory requires that
12 marginal costs must be higher than average costs to avoid consistently
13 experience economic losses over the long-term?³¹**

14 A. No, as applied to the TAM, which optimizes the Company's system on a short-term
15 (one year) basis. If an entity can sell an item at a price above the incremental cost to
16 produce the item, an economic benefit is realized. Fixed costs are omitted from
17 incremental cost analyses because they don't change. Incremental costs—often
18 referred to as marginal or relevant costs—are routinely used by the Company to
19 inform short-term decisions such as those assumed in the TAM.

20 **Q. Does the incremental price apply to all tons consumed at the plants?**

21 A. No. The incremental price applies to specific quantities of coal available at the price.

³⁰ Sierra Club/100, Burgess/1.

³¹ Sierra Club/100, Burgess/37.

1 This would include some tiered pricing in coal contracts and additional production
2 capacity at BCC.

3 **Q. Do you agree with Sierra Club's recommendation "that future TAM modeling**
4 **use input assumptions that are more reflective of the full cost of fuel"?³²**

5 A. No. Sierra Club fails to recognize fixed costs do not change and that by including
6 those costs in dispatch decisions, it actually increases costs paid by customers as
7 described in Mr. Webb's testimony.

8 **RESPONSE TO SPECIFIC SIERRA CLUB ADJUSTMENTS**

9 **Q. Sierra Club recommends an adjustment to the 2021 TAM that would replace the**
10 **fuel costs for the Jim Bridger, Hunter, Craig, Huntington, and Hayden plants on**
11 **the theory that those plants are (a) dispatching uneconomically; and (b) not**
12 **subject to minimum take requirements for 2021.³³ How do you respond?**

13 A. Most basically, Sierra Club is proposing an adjustment of [REDACTED] without ever
14 challenging the prudence of the underlying coal contracts. Sierra Club proposes to
15 replace actual coal fuel costs for these plants with a natural gas proxy price, implying
16 that the Company could actually replace the output from these coal plants with
17 natural gas generation. In addition, Sierra Club assumes there would be no market
18 impact due to the proposed change. There is no basis for these assumptions. The
19 bulk of this adjustment, [REDACTED], is related to replacing the fuel supply from
20 BCC at the Jim Bridger plant. Sierra Club assumes that BCC could continue as a
21 viable resource to fuel the Jim Bridger plant with zero volume. This is an incorrect

³² Sierra Club/100, Burgess/53

³³ Sierra Club/100, Burgess/72-73. For Hayden, the adjustment proposes to remove amounts over the minimum take.

1 assumption and this action would have significant cost impacts that Sierra Club did
2 not consider. Finally, the Commission has repeatedly approved PacifiCorp's fuel
3 supply strategy for the Jim Bridger plant as objectively reasonable and Sierra Club
4 has never challenged this finding in this or any other proceeding.

5 **Q. Please respond to Sierra Club's premise that these plants are dispatching**
6 **uneconomically.**

7 A. This premise is based on Sierra Club's incorrect theory that these plants should
8 dispatch at average, not incremental costs. As discussed above and by Company
9 witness Mr. Seth Schwartz and demonstrated by Mr. Webb's analysis, incremental
10 cost dispatch is beneficial for customers and reduces overall NPC.

11 **Q. Sierra Club contends that the coal supply subject to this adjustment,**
12 **approximately [REDACTED] tons, can be replaced with natural gas because there**
13 **are no minimum take provisions governing supply at these plants. Is this**
14 **correct?**

15 A. No. At the Jim Bridger plant, while there is no contract for minimum tons from BCC,
16 to remove [REDACTED] tons and reduce the output of BCC to zero would essentially
17 shut down BCC and it could not continue to be a viable resource. To do this would
18 be at a significant cost to the customer that has not been accounted for in Sierra
19 Club's analysis. This type of scenario was reviewed in the 2018 Fuel Plan, which
20 showed that it was not the lowest cost for the customer.

21 At Hunter, PacifiCorp is going through the procurement process for a new
22 CSA(s) and to assume a contract can be executed with no minimum take is

1 unrealistic. Mr. Schwartz's testimony discusses the purpose of minimum take
2 provisions, especially in coal markets with less liquidity.

3 At the Craig plant, while there is technically no minimum as it relates to the
4 coal purchases from the Trapper mine, PacifiCorp is a minority owner and as such
5 has limited control. A new contract is being negotiated between the owners.
6 PacifiCorp does not operate the Trapper mine and cannot arbitrarily adjust the mining
7 and purchases of coal at the Craig plant. As discussed in the case of BCC, to assume
8 that the Trapper mine output could be reduced to zero would essentially shut down
9 Trapper and it could not continue to be a viable resource. To do this would create
10 significant costs to the customer that have not been accounted for in Sierra Club's
11 analysis.

12 At Huntington, there is [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]

19 **Q. Sierra Club also recommends removal of certain fixed fuel costs included in the**
20 **2021 TAM.³⁴ How do you respond?**

21 **A. This adjustment removes the coal volumes subject to minimum take provisions from**

³⁴ Sierra Club/100, Burgess/27.

³⁵ Sierra Club/100, Burgess/75.

1 two contracts: the Black Butte contract and the Colstrip contract. There are numerous
2 issues with this adjustment. First, in the 2017 TAM, the Commission previously
3 rejected a challenge to minimum take provisions, recognizing that they are standard
4 term in coal contracts, required to obtain secure and reasonably priced coal supply.³⁶
5 Sierra Club completely ignores this precedent.

6 Second, [REDACTED] of the total adjustment of [REDACTED] is related to a
7 disallowance for the Black Butte contract. In the 2018 TAM, the Commission
8 acknowledged the reasonableness of the Company's near-term fuel supply strategy in
9 executing this contract.³⁷ Sierra Club does not address how its disallowance can be
10 reconciled with the Commission's past review and approval of PacifiCorp's strategy
11 to enter into the Black Butte contract.

12 Third, Sierra Club states "In [the] TAM, the NPC is the calculation of
13 projected power costs collected in rates and is based on a forecast of PacifiCorp's fuel
14 expense, wholesale purchase power expenses, and wheeling expenses less wholesale
15 sales revenue for the coming year."³⁸ Sierra Club's proposal to exclude "fixed fuel"
16 is in conflict with its own statement of what is included in the TAM.

17 **Q. Has any party challenged the prudence of the Colstrip contract in the 2020 TAM**
18 **or this proceeding?**

19 A. No. In Staff's review of the CSA, it found no term in the agreement which would
20 lead Staff to conclude the CSA is imprudent. Staff notes that the contract appears to

³⁶ See Order No. 16-482 at 9-11.

³⁷ Order. No. 17-444 at 13-14.

³⁸ Sierra Club/100, Burgess/12.

1 provide sufficient flexibility for PacifiCorp to adjust its obligations under the contract
2 in response to evolving circumstances.³⁹

3 **Q. Do you agree with Sierra Club proposals that the Commission require**
4 **PacifiCorp to (1) provide notice of the terms of any new or modified coal**
5 **contract within 30 days of execution; (2) include new or modified contracts with**
6 **minimum take provisions when seeking rate recovery and demonstrate their**
7 **prudence; and (3) include such contracts for review in the IRP process?**⁴⁰

8 A. No. None of these requirements are reasonable or necessary. PacifiCorp engages in
9 comprehensive resource and fuel planning processes. The Company's CSAs align
10 with the results of these processes and produce the least-cost, least-risk outcomes for
11 customers. As outlined above, the Commission has a well-established process to
12 review fueling strategies and coal contracts for the Company's coal plants in the
13 TAM and associated workshops. While Sierra Club's participation in this process has
14 been irregular, it has the ability to participate fully if it wishes to raise concerns about
15 new coal contracts. Moreover, adding these issues to the IRP would change the nature
16 of the IRP from a prospective planning process to a retrospective prudence review.

17 **Q. Sierra Club also asks the Commission to direct PacifiCorp to review its coal**
18 **contracts with renegotiation provisions and provide the Commission with a**
19 **report analyzing whether such renegotiations would reduce overall costs for**
20 **Oregon ratepayers. Please respond.**

21 A. Contract renegotiation provisions are typically included in long-term coal contracts

³⁹ Staff/300, Soldavini/14.

⁴⁰ Sierra Club/100, Burgess/83.

1 only. Because almost all of PacifiCorp's CSAs are now short-term, PacifiCorp does
2 not have renegotiation provisions it can unilaterally trigger. The provisions Sierra
3 Club cites as examples are environmental response provisions, which cannot be
4 invoked without the satisfaction of underlying conditions. As a result, there is no
5 basis for Sierra Club's recommendation.

6 **Q. Sierra Club specifically cites [REDACTED] CSAs with environmental**
7 **provisions that can allow for minimum take volumes to be reduced. Have there**
8 **been any changes to federal or state laws or regulations which could trigger**
9 **contract renegotiations per the environmental provisions of those contracts?**

10 A. No. Both of these contract provisions require actions outside the control of
11 PacifiCorp. These actions would include changes to laws and regulations by
12 governmental legislation or agencies that would impact these plants, which to date
13 have not occurred. For Sierra Club to make the statement "the minimum purchase
14 obligation if PacifiCorp chose to rely on such a provision would be 0 tons"⁴¹ based on
15 provisions PacifiCorp cannot trigger is highly misleading and shows a lack of
16 understanding of the provisions.

17 **RESPONSE TO CUB ADJUSTMENT ON NAUGHTON CONTRACT**

18 **Q. What is CUB's adjustment related to Naughton coal costs?**

19 A. Naughton's coal costs reflect the costs of closing Naughton Unit 3 under the
20 environmental response provision in the Naughton CSA. CUB argues that the costs
21 associated with reduced coal burning due to the natural gas conversion of Naughton
22 Unit 3, which it quantifies as [REDACTED], should be equally shared between

⁴¹ Sierra Club/100, Burgess/27.

1 customers and PacifiCorp because PacifiCorp was imprudent in executing the
2 Naughton contract in 2010.⁴² Specifically, CUB claims that the contract assumed that
3 Naughton would continue its business-as-usual operations, including operating
4 Naughton Unit 3 as a coal-fired generator.⁴³

5 **Q. Was the 2010 Naughton contract imprudent as CUB alleges?**

6 A. No, in fact the contract saved customers millions of dollars and provided flexibility to
7 convert Naughton Unit 3 to natural gas. Contrary to CUB's central allegation,
8 PacifiCorp did not ignore the potential that Naughton Unit 3 might cease operations
9 as a coal-fired generator.

10 **Q. Please provide the background on the 2010 Naughton contract negotiations.**

11 A. In 2010, PacifiCorp completed several months of negotiations with Chevron Mining
12 Inc. (the then owner operator of the Kemmerer mine) which resulted in two new and
13 separate agreements, collectively referred to as the 2010 Naughton contract. The first
14 agreement effectively became the Fifteen Amendment (15th Amendment) to the
15 existing 1992 CSA. The second agreement is the 2017 Agreement.

16 The 1992 CSA had an expiration date of December 31, 2016. Embedded in
17 the 1992 CSA were three different Price Reopener dates; January 1, 2001, January 1,
18 2006, and January 1, 2011. The detailed Price Reopener provision in the CSA called
19 for a renegotiation of the base purchase price under the CSA and allowed for a
20 specified time period (approximately three months) for the parties to negotiate and
21 reach agreement on a new purchase price. If the parties to the CSA were unable to

⁴² CUB/100, Jenks/13-14.

⁴³ *Id.* at 15.

1 reach an agreement on the new purchase price, PacifiCorp had the option to solicit
2 bona fide bids from unaffiliated coal suppliers and coal transporters (railroad and
3 trucking companies) to supply coal to the plant for the contractual equivalent tonnage
4 volume of coal that would need to comply with the plant's coal quality parameters.
5 The Seller (Chevron Mining) had the option to either accept the new pricing
6 established from the bona fide bid process and reset the purchase price under the
7 agreement for the next five years (2011-2016), or Seller had the option to reject the
8 bona fide bids and terminate the CSA, after one year.

9 PacifiCorp was able to build favorable forward pricing and flexibility into the
10 contract through negotiations with Chevron Mining at this time. The negotiations
11 resulted in the development of the two separate agreements mentioned above, the 15th
12 Amendment and the 2017 Agreement. Through the 15th Amendment, PacifiCorp was
13 able to eliminate the January 1, 2011 Price Reopener provision entirely and
14 established a new base purchase price. The estimated savings associated with
15 elimination of the January 1, 2011 Price Reopener provision and negotiating the new
16 purchase price under the 15th Amendment were estimated a [REDACTED] on a net
17 present value basis.⁴⁴

18 The favorable coal price realized from the settlement of the 2011 price
19 reopener was based upon the execution of both the 15th Amendment and the 2017
20 Agreement. In 2010, the Company estimated the total expected savings at
21 [REDACTED] dollars, of which the [REDACTED] was directly attributable to the

⁴⁴ These saving were calculated by making a delivered price comparison for the agreed upon new base purchase price against the alternative coal market options available and their respective pricing as calculated in accordance with the language of the Price Reopener provision over the remainder of the original 1992 CSA term (July 1, 2010 through December 31, 2016).

1 15th Amendment alone. Savings during the term of the 2017 Agreement are
2 significant and offset the increased coal supply costs associated with the decision to
3 cease burning coal on Naughton Unit 3 as of January 30, 2019.

4 **Q. Was the Company able to obtain other beneficial provisions in the contract?**

5 A. Yes. PacifiCorp was also successful in negotiating into the 2017 Agreement an
6 “Environmental Response” provision that allowed for a reduction in the annual take-
7 or-pay minimum tonnage requirement after 2017. This provision allowed PacifiCorp
8 to avoid paying the full contract price for minimum volumes if it determined the need
9 to adjust generation levels for any of the three units at the plant as a result of a change
10 in federal or state laws governing coal fired generation. The take-or-pay tonnage
11 level could be reduced down from [REDACTED] tons to [REDACTED] tons annually, given
12 a decision to shut down a particular unit at the plant. With this unique provision,
13 PacifiCorp would only be required to pay the Seller for a \$/per ton amount equal to
14 the “[REDACTED]” as referenced in the 2017 Agreement, as opposed to the
15 full cost associated with the Tier 1 coal purchase price. In 2020, the “composite
16 component” price is less than \$[REDACTED]/ton and is just over [REDACTED] percent of the Tier 1 coal
17 purchase price. Having the contractual right to pay a fraction of the full cost of coal
18 and thus avoid a contractual obligation to pay for a take-or-pay payment in the
19 amount of the 100 percent coal purchase price is a significant benefit to PacifiCorp’s
20 customers. In summary, the Naughton contract was prudent and has proved very
21 beneficial to customers.

VI. RESPONSE TO AWEC ADJUSTMENTS ON BCC DEPRECIATION

Q. AWEC makes two adjustments related to BCC depreciation and reclamation costs. First, AWEC recommends using a rate base valuation date of December 31, 2020, eliminating depreciation expense on minor capital plant additions through December 31, 2021, PacifiCorp's share of which is \$372,801.⁴⁵

How do you respond?

A. The depreciation expense embedded in BCC fuel costs reflects a relatively low amount of run-rate capital for 2021. The amounts and treatment of run-rate capital embedded in BCC fuel costs here are consistent with past TAM filings. Removing these amounts from depreciation expense included in BCC fuel costs would eliminate PacifiCorp's opportunity to recover these costs, even though AWEC does not challenge their prudence. AWEC provides no justification for this disallowance.

Q. In the last TAM, did the Company provided significant information to the parties related to Jim Bridger depreciation expense?

A. Yes. In docket UE 356, the 2020 TAM, I provided a report with my direct testimony addressing BCC depreciation expense.⁴⁶ In addition, before filing this case, the Company convened a workshop with the parties to address the issue.

Q. Did any party previously raise a concern about how run-rate capital is reflected in BCC depreciation expense as a component of Bridger fuel costs?

A. No.

⁴⁵ AWEC/100, Mullins/15.

⁴⁶ Docket No. UE 356, Direct Testimony of Dana Ralston, Confidential Exhibit PAC/202.

1 **Q. Second, AWEC recommends the Commission remove Oregon's share of the**
2 **reclamation trust fund and transfer it into a regulatory liability that accrues**
3 **interest at PacifiCorp's cost of capital.⁴⁷ How do you respond?**

4 A. PacifiCorp does not agree with this proposal. Most basically, AWEC bases it
5 adjustment on the fact that Oregon has a statute in place to cease receiving power
6 from coal generation by December 31, 2029 (SB 1547). Under the long-term fueling
7 strategy for the Jim Bridger plant, however, BCC will cease coal production
8 operations at the end of 2028, one year before the Oregon statute becomes effective
9 and the funding of the BCC reclamation trust fund is set up with that end date. There
10 is no need to change the current arrangements because of SB 1547.

11 **Q. Are there practical concerns raised by AWEC's adjustment?**

12 A. Yes. The reclamation trust fund is not solely owned by PacifiCorp. The
13 contributions to the trust are paid on a two-thirds / one-third basis by PacifiCorp and
14 BCC's joint venture partner Idaho Power subsidiary, Idaho Energy Resources. The
15 trust fund is managed by both PacifiCorp and Idaho Power. The trust fund is
16 prudently invested. The trust fund does make a return on its investments. The return
17 that the trust receives is invested back into the trust as a benefit to PacifiCorp's
18 customers.

19 **Q. AWEC claims that, without creating a regulatory liability, contributions**
20 **towards reclamation liability cannot be tracked. Is that true?**

21 A. No. By including reclamation costs within BCC's fuel costs, the amounts are subject
22 to annual review in the TAM. AWEC has not shown why it is imprudent for these

⁴⁷ AWEC/100, Mullins/16.

1 costs to be included with the cost of coal from BCC. These costs incurred are directly
2 related to the mining activity of BCC and therefore should be included as part of net
3 power costs.

4 **Q. AWEC states that it has identified what appears to be inconsistencies between**
5 **the amounts that PacifiCorp has included in the TAM and the amounts that it**
6 **has actually contributed to the trust fund. Is this correct?**

7 A. No, this is not correct. In AWEC's testimony, it claims the contribution amount for
8 2019 shown in the workpapers is materially less than the amount that was considered
9 in the 2019 TAM.⁴⁸ But AWEC failed to notice that the workpaper shows the sinking
10 fund calculation with the trust fund balance as of March 31, 2019.⁴⁹ The
11 contributions that AWEC claims are missing are the trust contributions for the
12 remaining nine months of 2019. AWEC also failed to note the contributions for
13 amounts charged to the underground mine.⁵⁰ The actual amount that was contributed
14 to the trust in 2019 was [REDACTED], whereas the amount that was included in the
15 2019 TAM was lower at [REDACTED].

16 **Q. AWEC recommends the Commission open an investigation to audit the trust**
17 **fund and require PacifiCorp to reconcile the amount of the trust fund**
18 **contributions historically included in rates and the amounts actually contributed**
19 **to the trust.⁵¹ How do you respond?**

20 A. As described above, AWEC's perceived "inconsistencies" stem from their

⁴⁸ See Tab "FR – Sinking Fund" cell "E15" of the workpaper "3.45M REV5 12-12-19/OPEX-CAPEX/ 01 OpsCostSchedule.xlsx".

⁴⁹ See "B15" of the workpaper "3.45M REV5 12-12-19/OPEX-CAPEX/ 01 OpsCostSchedule.xlsx".

⁵⁰ See cell "E47" of the workpaper "3.45M REV5 12-12-19/OPEX-CAPEX/ 01 OpsCostSchedule.xlsx".

⁵¹ AWEC/100, Mullins/17.

1 misunderstanding of the work papers associated with the trust fund. However, if the
2 Commission feels a need to audit the trust fund contributions and the amounts that are
3 included in costs, PacifiCorp will make the necessary information available at that
4 time.

5 **Q. Does this conclude your reply testimony?**

6 A. Yes.

REDACTED

Docket No. UE 375

Exhibit PAC/701

Witness: Dana M. Ralston

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of Dana M. Ralston

Commissioner Presentation

June 2020



FUEL RESOURCES
1407 West North Temple
Suite 110
Salt Lake City, Utah 84116

PACIFICORP

Presentation to Oregon Commissioners

2021 Oregon TAM, Docket No. UE 375

May 12, 2020

Confidential - Protected Information
Subject to General Protective Order No. 16-128

5/13/2020

Exhibit PAC/701
Ralston/1

1

Agenda

- 1)Minimum Take Levels at Naughton
- 2)Minimum Take Levels at Jim Bridger and other Plants
- 3)Jim Bridger Capacity Factors
- 4)Hunter Coal Contract
- 5)Westmoreland Bankruptcy

KEY FACTORS

Negotiating a New Coal Agreement

- 1) Evaluate & Understand Market Opportunities (Regional Coal Markets, Captive Mine, Transportation Options)
- 2) Contract Term
 - a) Short term vs. Medium term
 - b) Evaluate Extension Options and Opportunities
- 3) Delivered Pricing
- 4) Tonnage Volumes - Tonnage flexibility vs. tonnage commitments
- 5) Coal Quality Guarantees and Parameters
- 6) Transportation Considerations (Captive Mine, Trucking Options, Rail Access)
- 7) Contract Structure Type
 - a) Fixed Pricing
 - b) Index Based Pricing
 - c) Cost Plus Pricing
- 8) Take or Pay Requirements and Liquidated Damages (LD's)

MINIMUM TAKE OR PAY LEVELS

Managing Risk

Minimum take provisions are managed by:

- Nomination provisions
 - Minimum/Maximum tonnage provisions
- 1) Tonnage flexibility
 - 2) Percentage take flexibility
 - 3) Shortfall/Pre-delivery provisions
 - 4) Re-sell rights

CONTRACT MINIMUMS

Coal Supply Agreements – 2021 TAM Direct Filing

Plant	Coal Mine	Minimum Deliveries	Forecast Deliveries	Minimum %
Colstrip	Rosebud			
Craig	Trapper			
Dave Johnston	Coal Creek			
Dave Johnston	Caballo			
Dave Johnston Total				
Hayden	Twentymile			
Hunter	Unknown			
Huntington	Various			
Jim Bridger	Black Butte			
Jim Bridger	Bridger			
Jim Bridger Total				
Naughton	Kemmerer			
Wyodak	Wyodak			
Note: Deliveries are in tons and represent PacifiCorp share				

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NAUGHTON PLAN

Coal Supply Agreement

- 1) PacifiCorp has an existing CSA with Kemmerer Operations LLC. – Kemmerer Mine
 - a) Kemmerer mine is located adjacent to the Naughton Plant
 - b) Coal deliveries from the mine are delivered via conveyor belt from the mine to plant
- 2) CSA was effective 7/1/2010 and expires 12/31/2021

[REDACTED]

[REDACTED]

[REDACTED]

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NAUGHTON PLAN

Coal Supply Agreement - Continued

Future coal supply agreement will consider the following:

- 1) Shorter Term (up to 4-Years) – Units 1 & 2 shut down in 2025
- 2) Market opportunities
- 3) Tonnage flexibility
- 4) Delivered pricing
- 5) Coal quality considerations
- 6) Appropriate “take-or-pay” and or “Liquidated Damages” provisions

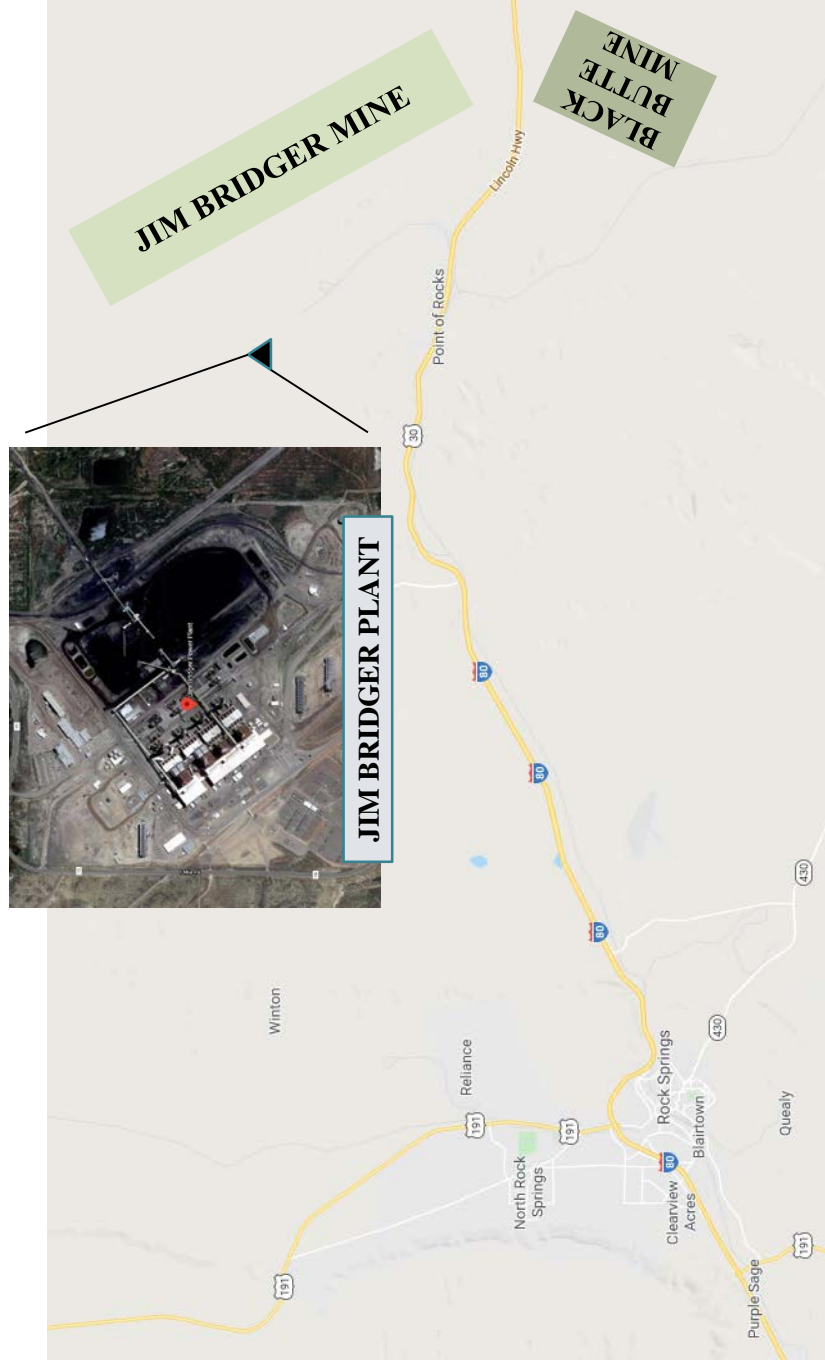
BACKGROUND

Jim Bridger Plant

- Largest plant on the PacifiCorp system – 2,120 MW (4 nearly identical units each with nominal 530 net MW capacity).
- PacifiCorp owns 66.7%; Idaho Power Company owns 33.3%
- Designed to burn local SW Wyoming coal with heat content in range of 9,000 Btu/lb to 10,000 Btu/lb.



LOCATION



- The Jim Bridger Plant is located on 1,000 acres of land 30 miles east of Rock Springs, Wyoming just north of I-80.
- Jim Bridger Mine is located adjacent and just east of the plant.
- Black Butte Mine is located 20 miles southeast of the plant.

PLANT LIFE

2019 Integrated Resource Plan (IRP) shows:

- Jim Bridger Unit 1 to retire in 2023 (Nameplate Capacity 354 MW).
- Jim Bridger Unit 2 to retire in 2028 (Nameplate Capacity 359 MW).
- Jim Bridger Unit 3 to retire in 2037 (Nameplate Capacity 349 MW) – SCR installed 2015.
- Jim Bridger Unit 4 to retire in 2037 (Nameplate Capacity 353 MW) – SCR installed 2016.

CY2021 – Fuel Supply Sources

- Bridger Coal Company (BCC) – Bridger Mine
- Lighthouse Resources, LLC - Black Butte Mine

BCC – BRIDGER MINE

Consists of two mining operations

- 1) Surface Mine (Two Draglines / Loaders / Trucks)
- 2) Underground Mine (Longwall Miner / One Continuous Miner)

All coal delivered from Bridger Mine is transferred on the mine's conveyor belts to the plant

LIGHTHOUSE RESOURCES, LLC

Black Butte Mine

- Surface Mining operation
 - Located approximately twenty (20) miles from the Jim Bridger Plant (Two Draglines / Loaders / Trucks)
 - All the Black Butte Coal is delivered via railcars (Union Pacific Railroad)
- 1) The unit train set is owned by the Jim Bridger plant
 - 2) The U.P. provides the locomotives and engineers

JIM BRIDGER PLANT

2021 Fueling Requirements

Annual generation requirements are expressed in consumed tonnage derived from PacifiCorp's budget using PacifiCorp Generation and Regulation Initiative Decision (GRID) model 2021 Oregon TAM assumes PacifiCorp will consume approximately [REDACTED] M tons

REDACTED

Exhibit PAC/701
Ralston/14

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JIM BRIDGER PLANT

2021 Fueling Forecast

Total Coal Deliveries forecast [REDACTED] M tons in the 2021 TAM
(PacifiCorp Share)

1) BCC total deliveries equals [REDACTED] M tons

2) Black Butte Deliveries equals [REDACTED] M tons

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BLACK BUTTE MINE

- 1) PacifiCorp & Idaho Power are both Parties (Buyers) under the Coal Agreement
- 2) Contract Term is four (4) years
 - a) Effective January 1, 2018; expires December 31, 2021
- 3) PacifiCorp's 2021 TAM deliveries are forecast to be [REDACTED] M tons
- 4) Transportation Agreement is aligned with the fuel agreement

REDACTED

Exhibit PAC/701
Ralston/16

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5/13/2020

16

JIM BRIDGER PLANT

Future Fueling Strategy

- 1) The plant's long term fuel supply will be satisfied with coal from both BCC and the Black Butte mine
- 2) For CY's 2021-2028, forecasted coal deliveries are comprised of:
 - a) BCC annual average is [REDACTED] tons (Pac Share) or 53% of plant requirements
 - b) Black Butte annual average is [REDACTED] tons (Pac Share) or 47% of plant requirements
 - c) Coal deliveries from BCC provides the flexibility for the plant
- 3) Future Black Butte agreements will be short-term in duration.....less than five (5) years
- 4) Future transportation agreements will align with the coal agreements

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JIM BRIDGER PLANT

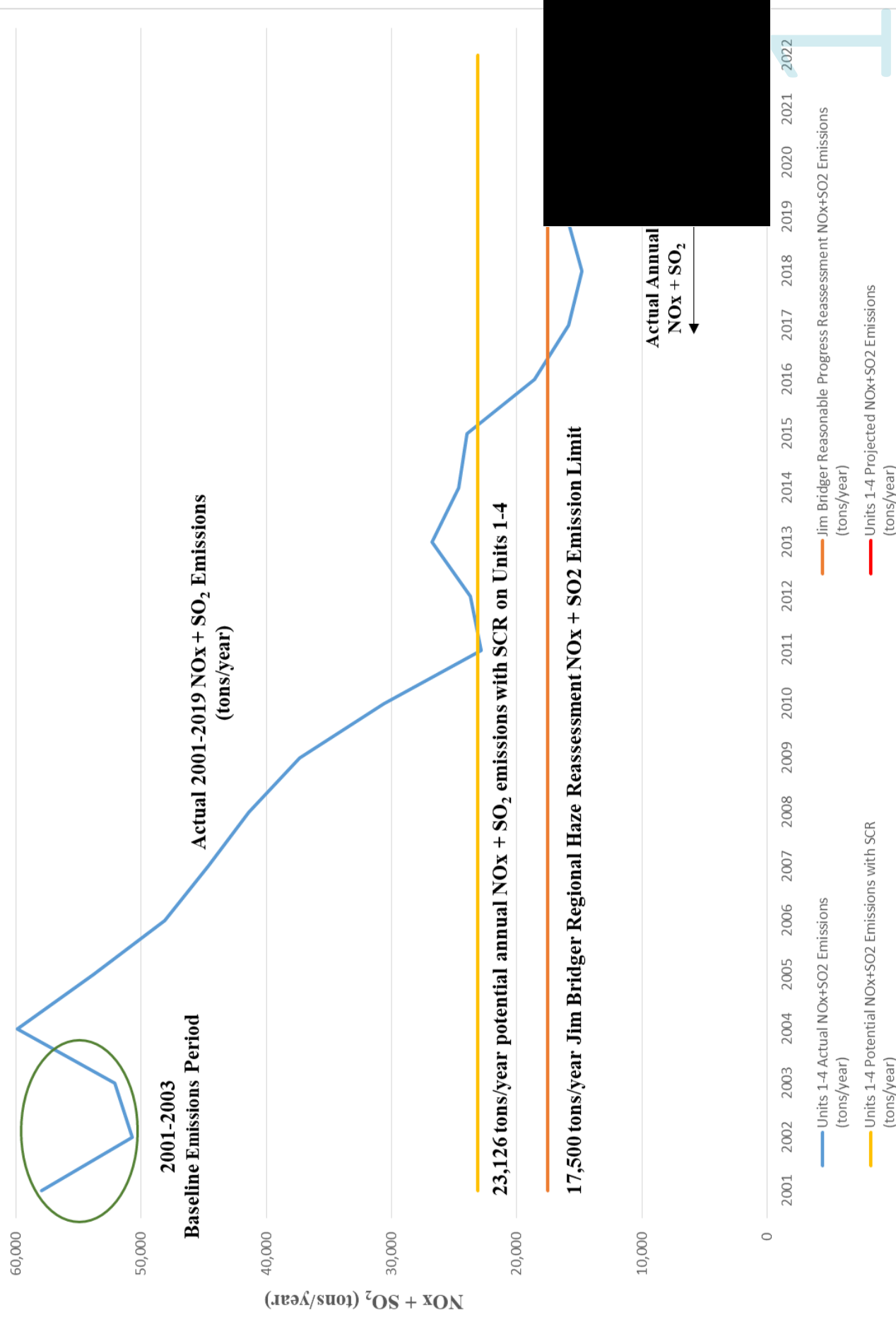
Emission Limits

PacifiCorp submitted the Jim Bridger regional haze ‘Reasonable Progress Reassessment’ application to Wyoming DEQ in February 2019. The application proposed implementation of plant-wide monthly nitrogen oxide (NO_x) and sulfur dioxide (SO₂) emission limits, as well as an annual total (NO_x + SO₂) emission limit in lieu of the requirement to install selective catalytic reduction (SCR) systems on Jim Bridger Unit 1 and Jim Bridger Unit 2.

As proposed, the limits would not become effective until January 1, 2022.

The application was submitted for compliance with EPA’s Regional Haze Rule and focuses on cost and visibility impacts analysis, comparing the proposed plant-wide NO_x + SO₂ limits against installation of SCRs on Bridger Units 1 and 2. The maximum potential to emit under either scenario are compared against ‘baseline’ emissions in 2001-2003, as required by the rule.

Jim Bridger NOx + SO₂ Emissions



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No. 16-128**

JIM BRIDGER PLANT

Emission Limits

The application did not propose a capacity factor limit or a coal throughput limit on the facility; however, the application uses a calculated effective annual average capacity of 76.3 percent to evaluate other environmental impacts of the proposal, including: changes in potential coal throughput (8.62M tons/yr); decreases in potential carbon dioxide (CO₂) emissions; decreases in coal combustion residuals (CCR) waste streams; water use; etc.

Wyoming DEQ has not yet finalized all aspects of its review or granted final approval of the application. Upon state approval, the application will be submitted to the Environmental Protection Agency (EPA) Region 8 for federal review and approval, which will include a public comment process.

If approved, the proposed limits would result in a restriction on plant's maximum plant-wide potential to emit. The plant's current operations and emissions are not analyzed under the application, because the analysis focuses on what the facility could emit, rather than what it does emit.

HUNTER PLANT

Future Coal Supply Agreement(s)

- 1) PacifiCorp's current CSA expires 12/31/2020
- 2) PacifiCorp commenced RFP process in November 2019
- 3) PacifiCorp currently involved in the RFP process and working with different Respondent Coal Companies
- 4) PacifiCorp is currently engaged in sensitive negotiations with the respondent Coal companies. No final terms have been agreed to.
- 5) The 2021 TAM filing has an estimated delivered price for Hunter based upon market price estimates from Energy Ventures Analysis (EVA) a reputable consulting firm

WESTMORELAND

Bankruptcy Information

- 1) PacifiCorp was impacted at two locations
 - a) Naughton Plant – Kemmerer Mine
 - b) Colstrip Plant – Rosebud Mine
- 2) The Westmoreland bankruptcy was bifurcated into two bankruptcies
 - a) Westmoreland-Kemmerer Mine bankruptcy completed in June 2019
 - i. Mine assets sold to Kemmerer Operations LLC (Secured Lenders Group)
 - ii. PacifiCorp CSA was assigned to Kemmerer Operations LLC
 - b) Westmoreland-Rosebud Mine bankruptcy completed in March 2019
 - i. Mine assets sold to Westmoreland Mining LLC (First Lien Creditors Group)
 - ii. New Mining company formed Westmoreland Rosebud Mining LLC
 - iii. PacifiCorp along with four other Colstrip owners executed a new CSA in December 2019

QUESTIONS?



Docket No. UE 375
Exhibit PAC/800
Witness: Doug Young

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Reply Testimony of Doug Young

June 2020

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

3 A. My name is Doug Young. My business address is 825 NE Multnomah Street, Suite
4 600, Portland, Oregon 97232. My present title is Director, Energy Supply
5 Management Financial Controller.

6 **I. QUALIFICATIONS**

7 **Q. Briefly describe your education and professional experience.**

8 A. I received a Bachelor's degree in General Science with Honors from University of
9 Oregon in 1995 and a Post-Baccalaureate certificate in Accounting from Portland
10 State University in 2000. I am a Certified Public Accountant licensed in the state of
11 Oregon currently in an inactive status. I have been employed by PacifiCorp since
12 2003 and have held a director level position since 2009. I took over responsibility for
13 the net power cost finance department at the end of 2019. Prior to working at
14 PacifiCorp, I worked at PricewaterhouseCoopers LLP as an auditor specializing in the
15 electric utility industry.

16 **II. PURPOSE AND SUMMARY OF TESTIMONY**

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

18 A. I provide an overview of coal generation forecasting in the PacifiCorp business plan
19 process and explain how the Company uses the forecasts produced under my
20 direction in its coal procurement process. I also respond to various issues raised in
21 the opening testimony of Mr. Ed Burgess, filed on behalf of Sierra Club, challenging
22 PacifiCorp's coal procurement process.

1 **Q. Please summarize your testimony.**

2 A. My testimony:

- 3 • Provides an overview of coal generation forecasting used in PacifiCorp's
- 4 business plan.
- 5 • Summarizes how PacifiCorp develops generation forecasts used in coal
- 6 supply agreement negotiations.
- 7 • Refutes Sierra Club's claim that PacifiCorp might use overstated generation
- 8 forecasts as a starting point for its coal contract negotiations and for
- 9 establishing minimum tonnages.
- 10 • Refutes Sierra Club's claim that there is "a 'vicious cycle' created by
- 11 PacifiCorp over-estimating coal forecasts leading to higher tonnage minimum
- 12 on new coal supply agreements."¹

13 **III. PACIFICORP'S GENERATION FORECASTING**

14 **Q. Please explain how PacifiCorp calculates net power costs (NPC) for its business**
15 **planning process.**

16 A. PacifiCorp's finance department calculates NPC over the 10-year business planning
17 horizon based on projected data using Generation and Regulation Initiative Decision
18 Tools (GRID). GRID is a production cost model that simulates the operation of the
19 Company's power system on an hourly basis.

20 **Q. Please explain how PacifiCorp uses forecasts of coal generation for business**
21 **planning purposes.**

22 A. PacifiCorp's finance department uses forecasts of coal generation in GRID to create

¹ Sierra Club/100, Burgess/30.

1 financial forecasts and budgets for coal consumed expense. The GRID model is run
2 annually to forecast coal costs for business planning purposes.

3 **Q. Please explain the steps that PacifiCorp takes to forecast coal generation for the**
4 **business plan.**

5 A. PacifiCorp's finance department obtains thermal availability, including planned
6 maintenance, variable operation and maintenance (O&M) unit costs, minimum load
7 levels and heat rate input/output curves from thermal plant management. Incremental
8 fuel costs and minimum take constraints are obtained from the Fuel Resources
9 department, including volumes available at those incremental prices. The finance
10 department loads the data inputs into GRID and runs the GRID model. GRID's coal
11 generation volume output is reviewed for reasonableness by comparing it to expected
12 targets based on historical coal generation volumes adjusted for forecasted changes in
13 load, renewables, and plant retirements.

14 **Q. How is the business planning process informed by PacifiCorp's integrated**
15 **resource plan (IRP)?**

16 A. The IRP is an important document that lays out the assets available to be modeled by
17 GRID for business planning purposes. Assumptions from PacifiCorp's IRP around
18 plant retirements and new resources are key inputs to the business plan GRID run.
19 The finance department works to keep the business plan in sync with the IRP as much
20 as possible. The business plan itself is not used to determine if new resources should
21 be retired or new resources added. That is the function of the IRP process. The
22 purpose of the business plan is to create a financial forecast assuming PacifiCorp has
23 a specific portfolio of assets available to serve loads.

1 **Q. Does PacifiCorp use a different NPC forecast for business planning as compared**
2 **to ratemaking?**

3 A. Yes. The business plan GRID forecast is run for a different purpose and at a different
4 time of year than GRID runs for ratemaking. The purpose of the business plan GRID
5 run is to try to capture recent market trends and volatility that could impact the
6 forecast year whereas the ratemaking GRID runs try to capture more normalized
7 results.

8 **Q. What is the current process for forecasting generation used in new coal supply**
9 **agreement procurement decisions?**

10 A. Working off of the business plan generation forecasts, PacifiCorp continually refines
11 its process for development of generation forecasts used to support coal contract
12 negotiations. Each new coal supply agreement presents unique facts and
13 circumstances. The current process uses the business plan generation forecasts as a
14 starting point, and then additional GRID runs are performed as needed. Multiple
15 departments are involved in the generation forecast process including representatives
16 from the Fuel Resources department, the Energy Supply Management department, the
17 Resources and Commercial Strategy department and the Energy Supply Management
18 Finance department.

19 **Q. Is it PacifiCorp's goal to develop the most accurate generation forecast possible?**

20 A. Yes. As described in the testimony of Mr. Seth Schwartz, minimum take and/or
21 liquidated damages provisions are a component of virtually all coal supply
22 agreements and are necessary to obtain favorable pricing and security of supply. It is
23 imperative to know the forecasted generation going into the negotiations so that

1 minimum take and liquidation damage levels can be set below the expected
2 generation as determined by GRID. GRID generation forecasts are used to provide
3 insight into the level at which a new minimum take or liquidated damages provision
4 can be set without locking PacifiCorp into generation levels that are higher than
5 necessary.

6 **Q. Please explain how this process provides the best information to PacifiCorp's**
7 **fuels department as they are conducting their negotiations.**

8 A. This process ensures the appropriate business units are involved in the review of the
9 generation forecast. It also allows for those business units to focus specifically on the
10 generation plant involved in the coal supply agreement negotiations. This ensures the
11 most recent market data at the time of the negotiations is relied upon for the fuel
12 procurement decision.

13 **IV. PACIFICORP'S RESPONSE TO SIERRA CLUB**

14 **Q. Sierra Club contends that "PacifiCorp might use the overstated generation**
15 **forecasts modeled in GRID as a starting point for its coal contract negotiations**
16 **and for establishing minimum tonnages."² Is this statement accurate?**

17 A. No, it is not accurate. Sierra Club claims that understated coal dispatch cost inputs
18 and minimum take constraints lead to overstating the generation forecast used for
19 contract negotiations. However, neither of these are inputs into PacifiCorp's
20 generation forecast process. The dispatch cost used for the GRID model is the
21 expected range of coal costs from potential sellers, and there are no minimum take
22 constraints applied in the forecast.

² Sierra Club/100, Burgess/60.

1 The most recent official forward price curve is used for the GRID run. As
2 discussed in Mr. David Webb's testimony, the use of incremental pricing rather than
3 average in the GRID dispatch tier is the standard method for determining an optimal
4 generation forecast. Additionally, the generation forecast is not influenced by prior
5 historical minimum take provisions that may have existed at the specific generation
6 plant. The generation forecast modeled in GRID represents PacifiCorp's best
7 estimate for expected generation levels.

8 **Q. Sierra Club additionally contends that there is "a 'vicious cycle' in terms of the**
9 **relationship between the coal contracting process and how plant dispatch is**
10 **projected."**³ **Is this statement accurate?**

11 A. No. Sierra Club's claim that PacifiCorp is over-forecasting fuel requirements for new
12 coal supply agreements is not correct. As discussed above, GRID scenarios are run
13 using a range of incremental coal costs, with no minimum take constraints and with
14 the updated market assumptions that are known at the time of the negotiation. This
15 does not result in an overstated forecast but rather a best estimate of forecasted
16 generation. Notably, Sierra Club has not pointed to any specific examples to support
17 its claim that PacifiCorp's generation forecasts produce coal oversupply.

18 **Q. Does PacifiCorp benefit from overstating generation forecasts used in coal**
19 **contracting negotiations?**

20 A. No. PacifiCorp does not benefit from contract minimum tonnage levels being set
21 higher than economic dispatch levels. There is no benefit from running higher cost
22 resources when lower cost resources can be run. PacifiCorp's interests are aligned

³ Sierra Club/100, Burgess/61.

1 with customer interests in trying to achieve the best possible forecast to be used for
2 new coal supply agreement negotiations. PacifiCorp's goal for the generation
3 forecast used for contract negotiations is to get the most accurate forecast, not an
4 overstated forecast. The Company's best interests lie in providing electricity at the
5 lowest reasonable cost for customers.

6 **Q. Does this conclude your reply testimony?**

7 A. Yes.

REDACTED

Docket No. UE 375

Exhibit PAC/900

Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

REDACTED

Reply Testimony of Ramon J. Mitchell

June 2020

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ATTACHED EXHIBITS

Exhibit PAC 901 – 2020 CAISO EIM Benefit Methodology Reply Filing

Exhibit PAC 902 – 2020 Colorado EIM Entrants Reply Filing

Exhibit PAC 903 – 2020 Flexible Ramping Product Reply Filing

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Mitchell/1

1 **Q. Are you the same Ramon J. Mitchell who previously submitted direct testimony**
2 **in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the**
3 **Company)?**

4 A. Yes.

5 **I. PURPOSE OF TESTIMONY**

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

7 A. My testimony sponsors PacifiCorp's forecast of energy imbalance market (EIM)
8 transfer benefits and EIM greenhouse gas (GHG) benefits for calendar year 2021,
9 which has been updated with recent EIM benefit information up to and including
10 April 2020. In addition, I respond to the testimony of the Public Utility Commission
11 of Oregon (Commission) Staff witness Ms. Moya Enright on adjustments to
12 PacifiCorp's EIM benefit actuals and forecasts. I also respond to the testimony of the
13 Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks on PacifiCorp's EIM
14 benefit forecast methodology. Finally, I respond to the testimony of Staff and the
15 Sierra Club witness Mr. Ed Burgess on efficient unit commitment and economic
16 dispatch decisions.

17 **Q. Please summarize your testimony.**

18 A. I update PacifiCorp's EIM transfer benefit forecast of [REDACTED] a [REDACTED] of
19 [REDACTED] from the initial filing.¹ This update takes into consideration the most
20 recent historical data and an updated official forward price curve (OFPC). I also
21 propose an update to PacifiCorp's EIM GHG benefit forecast of [REDACTED], a
22 [REDACTED] of [REDACTED] from the initial filing, which takes into consideration

¹ Unless otherwise stated, all EIM benefits calculations are total-company.

REDACTEDPAC/900
Mitchell/2

1 expected growth in GHG compliance costs and the most recent historical data. In
2 addition, I respond to the following concerns from other parties:

- 3 • I address Staff's concerns regarding the inputs into PacifiCorp's EIM benefit
4 forecast, the flexible transfer benefits, and the performance of the forecast
5 model.
 - 6 ○ Specifically, I show that PacifiCorp's internal calculation of EIM
7 benefits is more appropriate than the California Independent System
8 Operator's (CAISO) calculation of PacifiCorp's EIM benefits.
 - 9 ○ I provide a detailed workpaper explaining PacifiCorp's calculation of
10 EIM GHG costs.
 - 11 ○ I also demonstrate a sensitivity that shows the potential impact of all
12 new EIM entrants on PacifiCorp's EIM transfer benefits and explain
13 why it is not appropriate to update the methodology with this impact.
 - 14 ○ I propose an adjustment to account for forecasted growth in GHG
15 compliance costs.
- 16 • I update the flexible transfer benefits from the 2019 Integrated Resource Plan
17 (IRP) and provide the CAISO's calculation of PacifiCorp's flexible transfer
18 benefits, which total [REDACTED] for 2019.
- 19 • I demonstrate that it is appropriate to assess the EIM transfer benefit forecast
20 model's performance by using actual 2019 prices to back into the model's
21 estimate of actual 2019 EIM transfer benefits.
- 22 • Additionally, I discuss CUB's concern on Oregon's lack of experience with
23 forecasting intra-hour markets and their note that the forward prices in the

Company's OFPC are not day-ahead prices.

- I discuss the appropriate pricing strategy for wholesale market transactions such as sales for resale, the relationship between production costs and market prices in an efficient market, and the relationship between economic cycling and EIM benefits. Specifically, I show that after unit commitment and economic dispatch decisions have been made to serve retail load, the cost of energy for wholesale sales is the incremental cost of energy, not the average cost of energy.
- I also show that in an efficient market incremental production costs will at times be above market prices and that this is not an indicator of uneconomic operations but instead an outcome of least-cost dispatch which is beneficial to customers.
- Finally, I show that with the all-time low minimum generation levels of PacifiCorp's resources the least cost solution is no longer dependent on economic cycling but instead on online displacement.

II. UPDATES TO THE EIM BENEFIT FORECAST

Q. Please summarize changes to the EIM benefit forecast from the initial filing.

A. The proposed 2021 EIM benefit forecast incorporates a modified suggestion from Staff on year-over-year growth in GHG benefits to align with California Carbon Allowance (CCA) design. Additionally, the proposed 2021 EIM benefit forecast updates the OFPC to the March 2020 edition and updates the historical input variables to data up to and including April 2020.

REDACTEDPAC/900
Mitchell/4

1 **Q. What are the impacts to EIM benefits for each change to the EIM benefit**
2 **forecast relative to PacifiCorp's initial filing?**

3 A. The modified suggestion from Staff i [REDACTED] EIM GHG benefits from [REDACTED],
4 as of the initial filing, to [REDACTED]. The update of EIM GHG benefit actuals from
5 data available as of December 2019 with data up to and including April 2020
6 [REDACTED] EIM GHG benefits from [REDACTED] to [REDACTED]. For EIM transfer
7 benefits, updating with the latest estimates on solar generation that will be brought
8 online in the CAISO during 2020 and 2021 [REDACTED] the EIM transfer benefit
9 forecast from [REDACTED], as of the initial filing, to [REDACTED]. The OFPC
10 update from the December 2019 edition used in the initial filing to the March 2020
11 edition [REDACTED] the EIM transfer benefit forecast from [REDACTED] to
12 [REDACTED]. The update of the EIM transfer benefit actuals from data up to and
13 including December 2019 with data up to and including April 2020 [REDACTED] the
14 EIM transfer benefit forecast from [REDACTED] to [REDACTED].

15 **Q. Why has the OFPC update [REDACTED] the EIM transfer benefit forecast?**

16 A. The electric market prices and natural gas market prices that drive PacifiCorp's
17 forecast are tied to the Company's OFPC upon which PacifiCorp's net power cost
18 (NPC) is based. The market price forecasts for 2021 in the March 2020 OFPC are
19 [REDACTED] for the summer months than the market price forecasts for 2021 in the
20 December 2019 OFPC. The OFPC is a representation of expected market prices and
21 is the Company's best forecast of conditions in 2021. This expectation of [REDACTED]
22 market prices in the summer of 2021, relative to the prior OFPC, drives the [REDACTED]
23 EIM transfer benefit forecast.

REDACTEDPAC/900
Mitchell/5

1 **Q. Why are forecast market prices in the summer months of 2021 [REDACTED] than they**
2 **were expected to be at the end of last year?**

3 A. The change in market price outlook is most likely driven by current expectations of
4 future Western Electricity Coordinating Council (WECC) load resulting from
5 cascading and persisting effects of the ongoing coronavirus pandemic on the region's
6 economy. These effects are anticipated to persist into 2021.

7 **Q. Why has the inclusion of March 2020 to April 2020 actual EIM benefits in the**
8 **forecast model [REDACTED] the EIM transfer benefit forecast?**

9 A. EIM spring import benefits were steadily and unwaveringly [REDACTED] year over year
10 in both PacifiCorp East (PACE) and PacifiCorp West (PACW). However, in the
11 spring of 2020 the EIM import benefits [REDACTED] expectations and [REDACTED] the
12 prior year's benefits (as illustrated in Confidential Figure 1) even though market
13 prices are as low in the spring of 2020 as they were during prior spring months. This
14 new relationship between market prices and EIM spring import benefits suggests a
15 future expectation of [REDACTED] EIM import benefits in the spring, all other things
16 equal.

REDACTED

1

Confidential Figure 1

2 **Q.** Why have EIM benefits [REDACTED] expectations even though market prices
3 are as expected?

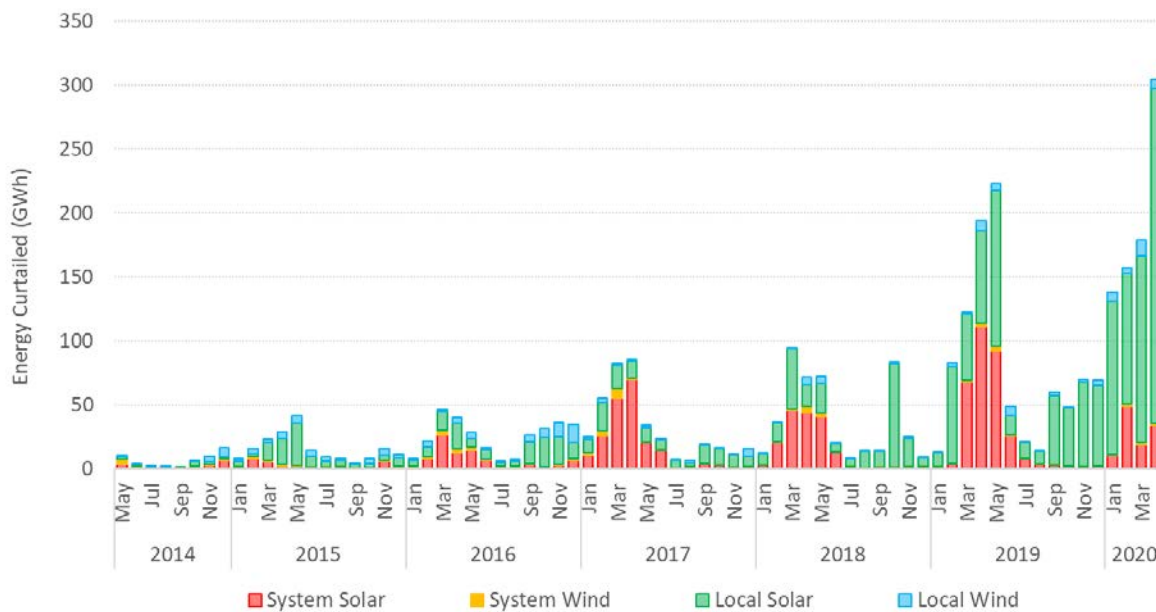
4 A. Spring oversupply conditions were still present in the CAISO during the spring of
5 2020. However, internal transmission congestion within the CAISO due to a series of
6 transmission outages during the first and second quarters of 2020 along with
7 restrictive transmission capacity ratings during the second quarter of 2020 led to large
8 amounts of oversupply being curtailed within the CAISO rather than flowing into the
9 wider EIM footprint. The level of the red “System Solar” plots in Figure 2 show a
10 measure of this oversupply that flowed into the wider EIM footprint. [REDACTED]

11

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Mitchell/7

1 [REDACTED]. The level of the
 2 green bars in Figure 2 show a measure of the oversupply that would have flowed into
 3 the wider EIM footprint were it not for internal CAISO congestion. [REDACTED]

4 [REDACTED]
 5 [REDACTED]

Figure 2 - CAISO Solar Curtailments

7 **III. RESPONSE TO STAFF ON EIM BENEFIT ACTUALS AND FORECASTS**

8 **A. Model Inputs**

9 **Q. Staff has concerns regarding the inputs to PacifiCorp's forecast of EIM benefits.**

10 **Please elaborate on these concerns.**

11 **A.** Staff is primarily concerned with four issues: (1) the discrepancy between
 12 PacifiCorp's calculation of calendar year 2015 to 2016 EIM benefits as compared to
 13 the CAISO's calculation of these benefits; (2) PacifiCorp's calculation of actual EIM
 14 GHG costs; (3) the fact that PacifiCorp only accounts for the impact of new EIM

REDACTED

1 entrants when they bring additional transmission into the EIM that connects
2 PacifiCorp to the CAISO; and (4) PacifiCorp's lack of forecasted growth in CCA
3 prices which drive GHG costs.

4 **Q. What is Staff's concern with calendar year 2015 to 2016 EIM benefits?**

5 A. Staff notes large differences between PacifiCorp's calculation of calendar years 2015
6 and 2016 PacifiCorp EIM benefits as compared to the CAISO's calculation of these
7 benefits. Specifically, the CAISO's calculation shows [REDACTED]

8 [REDACTED].²

9 **Q. Why does the CAISO's calculation of PacifiCorp's EIM benefits [REDACTED]
10 [REDACTED] from PacifiCorp's calculation of its EIM benefits in 2015 and 2016?**

11 A. Prior to 2017, the CAISO's calculation of EIM benefits was markedly different than
12 PacifiCorp's EIM benefit methodology, in that it constrained a resource's capability
13 to support transfers in the cost calculation. The change in methodology after 2016 is
14 denoted by the CAISO in the CAISO's 2020 Q1 version of the EIM benefit
15 methodology document in which the CAISO states:

16 Prior to the 2016 Q4 report, we used the resources' [real time
17 dispatch (RTD)] dispatching limits from the EIM in the
18 counterfactual. The EIM dispatching limits are 10-minute
19 ramp limited in RTD, and they may be overly constraining for
20 the counterfactual [...]. From Q2 of 2017, we decided not to
21 use EIM calculated limits.³

²Staff/200, Enright/33, Confidential Figure 7.

³PAC/Exhibit 901, Page 4, EIM Quarterly Benefit Report Methodology.

REDACTEDPAC/900
Mitchell/9

1 **Q. In non-technical terms, what does the CAISO's statement on the change in the**
2 **EIM benefit calculation mean?**

3 A. Prior to calendar year 2017, the CAISO would develop a balancing authority area
4 (BAA)-level resource stack to determine the costs associated with EIM exports or the
5 avoided costs associated with EIM imports. However, for each resource, the CAISO
6 would only allow 10 minutes' worth of energy to be included in the resource stack.
7 For example, if PacifiCorp was importing 500 megawatt-hours (MWh) and a resource
8 was decremented to allow the import and had a 4 megawatt (MW)/minute ramp rate,
9 it would only be allowed to contribute 40 MWh towards the 500 MWh import in the
10 benefit calculation's resource stack. Since this resource stack was limited to
11 10 minutes' worth of energy from each resource, it failed to correctly account for the
12 resources that supported EIM transfers. As a result, the CAISO's calculation
13 frequently found itself going too far down or up the stack and consequently [REDACTED]

14 [REDACTED]
15 These lower/higher cost resources that were attributed to supporting the EIM transfers
16 resulted in an [REDACTED] of EIM benefits.

17 **Q. Please provide an example of the situation you describe on the CAISO's ramp**
18 **limited EIM benefit calculation.**

19 A. The resource stack is built up from the lowest cost participating resource to the
20 highest cost. Using PACE as an example, a stack might start with wind resources and
21 end with gas peakers (simple cycle combustion turbines). Building on this example,
22 if PACE is a net exporter of 500 MWh of energy in the EIM, the CAISO would find
23 the marginal resource in PACE's resource stack and traverse down the stack by

REDACTED

1 500 MWh. The cost of the resources picked up as the stack is traversed down by
2 500 MWh is assumed to be the cost of energy that supplied the 500 MWh of exports
3 (EIM exports are incremental to serving load). However, since the stack was
4 constrained to 10 minutes of energy from each resource, the CAISO might end up
5 traversing right down the stack into PacifiCorp's wind resources. In the final
6 analysis, the CAISO's calculation might end up showing that PacifiCorp dispatched
7 upwards 250 MWh of wind generation to serve the 500 MWh of EIM exports. The
8 nonsensical result in this situation stems from the fact that the only way to dispatch
9 wind generation upwards is to have the wind blow harder or to avoid curtailment.
10 Consequently, the EIM benefit in this example implies that PacifiCorp instructed the
11 wind to blow harder or to avoid curtailment by 250 MWh to market the excess energy
12 into the EIM. From a financial perspective [REDACTED]
13 [REDACTED] for the 500 MWh of energy since the 250 MWh of wind receives
14 production tax credits for each MWh of energy produced, which results in a marginal
15 resource cost that is so low as to be negative. However, in reality the excess energy
16 of 500 MWh would have all come from thermal generation, which has positive fuel
17 costs.

18 **Q. Is it reasonable to use PacifiCorp's calculation of EIM benefits for 2015 and**
19 **2016 as inputs into the EIM transfer benefit forecast model?**

20 A. Yes. In contrast to the CAISO, PacifiCorp's benefit calculation did not have the
21 aforementioned ramping limitation. In fact, PacifiCorp identified the issue in the
22 CAISO's benefit calculation and collaborated with them to make changes to their
23 benefit methodology to more accurately reflect EIM benefits for each EIM entity.

REDACTED

1 **Q. What is Staff's concern with PacifiCorp's calculation of actual EIM GHG costs?**

2 A. Staff was unable to verify that PacifiCorp calculated its EIM compliance costs (GHG
3 costs) as stated by the Company.

4 **Q. How does PacifiCorp intend to remedy this issue?**

5 A. PacifiCorp has provided a workpaper for the month of November 2019 that shows the
6 EIM GHG costs in exacting detail, starting with the energy attributed by the CAISO
7 in the EIM as serving CAISO load and ending with the dollar impact per generating
8 resource of the procured, required CCAs. The calculation methodology is identical
9 by month and this data should allow Staff to verify PacifiCorp's calculation of its
10 EIM GHG costs. Furthermore, as annotated and displayed in the workpaper, the
11 CAISO's calculation of PacifiCorp's EIM GHG costs is methodologically identical to
12 PacifiCorp's calculation of its EIM GHG costs.

13 **Q. What is Staff's concern with new EIM entrants?**

14 A. Staff notes that in prior transition adjustment mechanism (TAM) filings they
15 witnessed [REDACTED] EIM benefits in line with the addition of new entrants to the
16 market.⁴ In PacifiCorp's proposed forecast models, the addition of new EIM entrants
17 is valued based on only the additional import transmission capacity between
18 PacifiCorp and the CAISO that each new EIM entrant brings to the table. Staff has
19 two major concerns on this issue. The first is that PacifiCorp's understanding of the
20 expected EIM entrants in 2021 is based on outdated information and fails to capture
21 four additional utilities that Staff claims will join the EIM in 2021. Staff's second
22 concern is that PacifiCorp, by only valuing the aforementioned import benefits

⁴Staff/200, Enright/38, lines 18-19.

REDACTEDPAC/900
Mitchell/12

1 contributed by each new EIM entrant, has failed to value the export benefits that the
2 introduction of each new EIM entrant into the market might facilitate. Staff notes
3 that PacifiCorp's import benefits account for only [REDACTED]⁵ of the Company's
4 transfer benefits in calendar year 2019.

5 **Q. Do you agree with Staff that PacifiCorp's forecast did not account for four**
6 **utilities that will be joining the EIM in 2021?**

7 A. No. Staff asserts that PacifiCorp failed to account for Xcel Energy, Black Hills
8 Colorado Electric, Colorado Springs Utilities and Platte River Power Authority based
9 on an article published by Black Hills Energy in December 2019.⁶ The article states
10 that "the [utilities] will be working with the [CAISO] to finalize the implementation
11 agreement [...] with a target of 2021." However, in an official article published by
12 the CAISO in May 2020, the CAISO states that these four utilities will be joining the
13 EIM in 2022.⁷

14 **Q. How has PacifiCorp addressed Staff's concerns surrounding the EIM benefit**
15 **forecast failing to account for the impact of new EIM entrants on export**
16 **benefits?**

17 A. The forecast proposed in initial testimony accounts for the impact of new EIM
18 entrants on EIM import benefits based on transmission capacity connecting
19 PacifiCorp to the CAISO. PacifiCorp has conducted a sensitivity to account for the
20 impact of new EIM entrants on EIM export benefits by introducing a new variable
21 into the two export models that tracks the percentage of WECC load served by the

⁵Staff/200, Enright/40, Confidential Figure 9.

⁶Staff/202, Enright/27.

⁷PAC/Exhibit 902.

1 EIM. As EIM entities join the market this percentage increases proportional to the
2 size of the new entity.

3 **Q. How does this addition of a variable which tracks EIM load as a percentage of**
4 **WECC load affect the EIM benefit forecast?**

5 A. With the addition of a new variable that tracks the percentage of WECC load served
6 by the EIM (EIM load) into the PACE export model, a [REDACTED] relationship is
7 observed between PACE export benefits and EIM load and a [REDACTED] relationship is
8 observed for PACW export benefits. Specifically, for every 10 percent increase in
9 EIM load, the PACE export benefits [REDACTED] by approximately [REDACTED] and the
10 PACW export benefits [REDACTED] by approximately [REDACTED].

11 **Q. What is PacifiCorp's proposal regarding the modeling of new EIM entrants?**

12 A. PacifiCorp does not propose to include EIM load in its export models at this time.
13 The relationship between EIM load and EIM benefits found in the forecast models is
14 solely based on the [REDACTED] between the [REDACTED] in PacifiCorp's
15 EIM transfer benefits and the average historical growth in EIM load. However, the
16 most recent 12 months of EIM transfer benefits show a [REDACTED] in these benefits
17 relative to its [REDACTED]. Based on this recent data PacifiCorp does
18 not believe that further expansion of the EIM will lead to the level of [REDACTED] EIM
19 benefits that the current [REDACTED] implies.

1 **Q. What is Staff's concern with PacifiCorp's lack of forecasted growth in CCA**
2 **prices?**

3 A. Staff notes that GHG allowance prices (CCA prices) are designed to increase each
4 year.⁸ PacifiCorp's current GHG benefit forecast is a flat forecast that doesn't
5 contemplate increases or decreases in upcoming years due to the constantly evolving
6 GHG policy environment.

7 **Q. What is PacifiCorp's response to Staff's concern on the lack of forecasted**
8 **growth in CCA prices?**

9 A. Staff suggests that PacifiCorp increase the GHG benefit forecast by five percent plus
10 inflation each year. As CCA prices increase, the spread between the GHG revenue
11 and the GHG cost increases for all resources that are infra-marginal. This spread is a
12 resource's GHG benefit. However, for all pollutant emitting thermal resources this
13 spread is relatively small. Only for hydroelectric resources, which have no GHG
14 cost, is the spread substantial. Consequently, the GHG benefits for thermal resources
15 will remain relatively constant while the GHG benefits for hydroelectric resources
16 will increase in proportion to the increase in GHG cost. This is conceptually the
17 intent behind the design that increases CCA prices year over year, to create scarcity in
18 the market and economically incentivize non-emitting generation. Consequently,
19 PacifiCorp proposes that only the hydroelectric resources' GHG benefits be increased
20 by five percent plus inflation. However, given that recent CCA prices have been
21 declining in the auction and in the spot market,⁹ PacifiCorp proposes to assume a

⁸Staff/200, Enright/41.

⁹https://ww3.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf

REDACTED

1 zero percent increase in 2020 before calculating 2021 benefits. Additionally,
2 PacifiCorp proposes to revisit the proposed benefit increase on an annual basis to
3 ensure that the expected price increase continues to be a reasonable assumption.
4 Forecasted EIM GHG benefits of [REDACTED] were proposed in the initial filing.
5 Using the same inputs that produced the aforementioned GHG benefit forecast,
6 without updated data, and then incorporating the above proposal, the forecasted EIM
7 GHG benefits for 2021 increases to [REDACTED]. This change results from the
8 expected growth in the EIM GHG benefits from hydroelectric resources which incur
9 no cost and whose EIM GHG benefits increase in proportion with the increase in
10 CCA prices.

B. Flexible Transfer Benefits

12 **Q. Staff has concerns regarding PacifiCorp's valuation of flexible transfer benefits.**
13 **Please elaborate on these concerns.**

14 **A.** Staff has two concerns. The first is that PacifiCorp does not calculate the
15 revenue/costs derived from the flexible ramping product offered in the EIM and that
16 they would like to see the CAISO's calculation of these benefits for PacifiCorp. The
17 second concern is that the EIM diversity benefit that reduces PacifiCorp's regulation
18 reserve holdings has not been updated since July 2018.

REDACTED

1 **Q. Why does PacifiCorp not calculate the benefits received from the flexible**
2 **ramping product in the EIM?**

3 A. The flexible ramping product is not properly deliverable due to current EIM issues
4 that the CAISO is currently conducting a stakeholder initiative on¹⁰ and the benefits
5 that would accrue if the product was properly deliverable are insubstantial.

6 **Q. What is the CAISO's calculation of PacifiCorp's flexible ramping product**
7 **benefits?**

8 A. PacifiCorp has requested these calculations and the CAISO has to-date not provided
9 the requested information. However, PacifiCorp has managed to obtain the output of
10 the CAISO's calculation of the various components that make up the CAISO's
11 calculation of PacifiCorp's EIM benefits. This output is at the five-minute
12 granularity and has no formulas. However, this data should satisfy Staff's request to
13 see the breakdown of the EIM benefits into the different categories as used by and
14 calculated by the CAISO. Based on this data the CAISO shows a [REDACTED] benefit from
15 flexible ramp transfers for calendar year 2019.

16 **Q. Staff notes that PacifiCorp has not updated the EIM diversity benefit that**
17 **reduces PacifiCorp's regulation reserve holdings since July 2018. What is the**
18 **updated EIM diversity benefit in megawatts?**

19 A. PacifiCorp's 2019 IRP flexible reserve study found 104 average megawatts (aMW) of
20 regulation reserve benefits attributable to participation in the EIM. This value is
21 applied as a credit to the Generation and Regulation Initiative Decision Tools (GRID)
22 model's regulation reserve requirement and lowers NPC. PacifiCorp updated the

¹⁰ PAC/Exhibit 903, pages 3-6.

1 EIM diversity benefit input of the 2019 IRP's flexible reserve study and found
2 92 aMW attributable to participation in the EIM.

3 **Q. How has the regulation reserve benefits attributable to the EIM decreased over**
4 **time?**

5 A. Load, wind and solar forecast errors have decreased year over year. The EIM
6 regulation reserve benefit is based on the EIM diversity benefit. This diversity
7 benefit is a function of the diversity of loads and the variability of resources in the
8 EIM as it pertains to uncertainty (forecast error). To use an illustrative example,
9 without the EIM, if PacifiCorp balances its system on an hour-ahead basis with an
10 expectation of 100 MWh of wind generation and the wind generation comes in at
11 90 MWh in real-time, then PacifiCorp would need to deploy 10 MW of upward
12 regulation reserves to balance the 10 MWh shortfall (uncertainty) that materialized
13 due to wind forecast error. Simultaneously, without the EIM, if Portland General
14 Electric Company (PGE) balances with an expectation of 100 MWh of wind
15 generation and 110 MWh materialized in real-time, then PGE would need to deploy
16 10 MW of downward reserves to balance the 10 MWh surplus (uncertainty) that
17 materialized due to forecast error. With both utilities in the EIM, PGE's 10 MWh
18 surplus would be used to cover PacifiCorp's 10 MWh shortfall and neither BAA
19 would need to deploy regulation reserves. This would be considered an EIM
20 diversity benefit of 10 MW due to the uncertainty present in both BAA's generation
21 forecasts. However, as the load, wind and solar industry improves forecast accuracy
22 and reduces the associated forecast error, the need for off-system assistance in real-
23 time regulation decreases and the associated EIM diversity benefit decreases

1 correspondingly. Keeping with the prior example, assume that forecast accuracy
2 improves and that the wind forecast is off by 5 MWh in both BAAs instead of the
3 10 MWh in the prior example. In this scenario the EIM diversity benefit is 5 MW.
4 This is a decrease in diversity benefit because of an improvement in forecast
5 accuracy. This interplay between forecast accuracy and EIM diversity benefits has
6 been the trend in recent years.

7 **C. Forecast Model Performance**

8 **Q. Staff has concerns regarding PacifiCorp's method of assessing model**
9 **performance.¹¹ How did PacifiCorp assess model performance?**

10 A. PacifiCorp assessed its model's performance and compared it to the performance of
11 alternative models through backtesting. Backtesting is a method where historical data
12 is split into two portions, a training set and a test set. A model is developed using
13 only data from the training set and then given the task to forecast the test set. The
14 model's forecast of the test set is compared to the actual test set and the difference
15 gives a measure of model performance. In January 2020, historical EIM benefit data
16 from January 2015 to December 2019 was split into two sets. The training set was
17 2015 to 2018 and the test set was 2019. Each model in assessment was developed
18 using only the training set (2015 to 2018) and then given the task of forecasting the
19 test set (2019). The EIM benefit forecast of the test set was compared to the actual
20 EIM benefit observed in the test set and PacifiCorp's model showed itself to be more

¹¹ Staff/200, Enright/38.

1 reliable than the alternatives.¹² This backtest approach is standard in the forecasting
2 industry; however, Staff found the approach to be problematic.

3 **Q. Why did Staff find the backtest approach, in which model performance is**
4 **assessed, problematic?**

5 A. Staff notes that if PacifiCorp were actually forecasting 2019 EIM benefits in the year
6 2018 then it would not know the actual 2019 prices and consequently it is
7 inappropriate to use actual 2019 prices to forecast the test set.¹³ Staff recommends
8 that PacifiCorp forecast the test set using the 2019 price forecast that would have
9 been available in the year 2018. However, if the forecast of 2019 prices made in the
10 year 2018 were used to forecast the test set, instead of actual 2019 prices, then the
11 endeavor changes from an assessment of only the models' performance to include an
12 assessment of the accuracy of the price forecast. By using actual 2019 prices to
13 forecast the test set, PacifiCorp is evaluating the structure and fundamentals of the
14 models by removing all forecasted inputs from the table and allowing the models
15 perfect foresight.

16 **Q. Why would you want to allow the models perfect foresight in an assessment of**
17 **their performance?**

18 A. If PacifiCorp allows the models to forecast the test set with perfect foresight (by using
19 actual 2019 prices) and the results of a model's forecast is inferior to the alternative
20 models when compared to actual 2019 EIM benefits, then there is reason to question
21 the structure of the inferior model. If the results of a model's forecast are superior to

¹² PAC/200, Mitchell/16-17.

¹³ Staff/200, Enright/38.

1 the alternative models, then it is fair to say that the superior model is more reliable.
2 However, without perfect foresight PacifiCorp can only come to the conclusion that
3 either the model or the price forecast input is inferior or superior and the Company
4 has no way of telling which one (the model or the price forecast) is at fault.

5 **Q. Why would it be inappropriate to forecast 2019 EIM transfer benefits using only**
6 **data that was available prior to 2019?**

7 A. After performing the backtests and comparing a model's performance with that of its
8 alternatives in 2019 using actual 2019 prices (perfect foresight), the only purpose
9 served by using 2019 prices that were available in the year 2018 (imperfect foresight)
10 to conduct an additional round of assessment is to evaluate the predictive power of
11 the 2019 price forecast made in the year 2018. The price forecasts used in the EIM
12 transfer benefit forecast models come from the Company's OFPC which is used in all
13 aspects of the Company for all forward looking analyses. Specifically, all of NPC
14 and the results of the GRID model use the OFPC to forecast future periods' NPC.
15 The intent of the backtests is to test the performance of the EIM transfer benefits
16 model, and only the model.

17 **IV. RESPONSE TO CUB ON EIM BENEFIT FORECAST METHODOLOGY**

18 **Q. Does CUB challenge the level of the Company's EIM benefits included in this**
19 **case?**

20 A. No. CUB accepts the results of the Company's forecast but does not endorse the
21 methodology the Company used.¹⁴ CUB notes that forecasting intra-hour markets is

¹⁴ CUB/100, Jenks/22.

1 not something that Oregon has a lot of experience with.¹⁵ Based on this premise,
2 CUB promotes caution on the endorsement of PacifiCorp's EIM transfer benefit
3 forecast methodology. CUB further goes on to note a difference in prices as used by
4 the EIM, which are at the 5-minute and 15-minute granularity and the hourly prices as
5 used by the GRID model which are at the 60-minute granularity.

6 **Q. How does PacifiCorp's EIM transfer benefit forecast methodology approach**
7 **intra-hour forecasting given that forecasting intra-hour markets is new territory**
8 **for many stakeholders?**

9 A. The EIM benefit forecast methodology is a monthly aggregate forecast. It relies on
10 the Company's OFPC, which is a monthly price forecast. The aggregation of intra-
11 hour benefits into a monthly total eliminates the volatility observed in intra-hour EIM
12 prices and eliminates any intra-hour EIM transfer benefit volatility in the historical
13 data. Effectively, by using monthly aggregates, the EIM benefits are normalized both
14 in the historical data and in the forecast data. There is no adverse impact to the EIM
15 benefit forecast due to the fact that the EIM is an intra-hour market.

16 **Q. Does CUB have any other concerns regarding PacifiCorp's EIM transfer benefit**
17 **forecast methodology?**

18 A. Yes. CUB notes that although the day-ahead prices are related to the EIM transfer
19 benefits, the forward prices from the OFPC used to forecast EIM transfer benefits are
20 made more than one year in advance and consequently are not actually day-ahead
21 prices. However, those forward prices in the OFPC are based on observed market
22 forwards and therefore reflect the Company's best expectation of conditions in 2021

¹⁵ CUB/100, Jenks/20.

1 and are used in the EIM transfer benefit forecast as a forecast of day-ahead prices.

2 Furthermore, these OFPC prices are the prices that are used in the GRID model, as a

3 forecast of day-ahead prices, to forecast NPC and also used in all aspects of the

4 Company for all forward-looking analyses.

5 **Q. Has CUB commented on PacifiCorp's EIM GHG benefit forecast methodology?**

6 A. No.

7 **Q. Has CUB made any recommendations or proposed any alternatives to**

8 **PacifiCorp's EIM transfer benefit forecast methodology other than**

9 **recommending it not be approved?**

10 A. No.

11 **V. EFFICIENT UNIT COMMITMENT AND ECONOMIC DISPATCH**

12 **Q. Please provide an overview of how PacifiCorp's operates its system.**

13 A. PacifiCorp operates its system on an integrated basis across its six-state territory. For

14 system balancing purposes, PacifiCorp relies on regional energy markets for

15 wholesale energy transactions. These markets are the bilateral spot markets at five

16 major regional hubs along with the EIM, which integrates the majority of WECC

17 load. PacifiCorp's geographic footprint allows it to take advantage of efficiencies

18 and economies from an operational perspective due to retail load characteristics,

19 variable wind and solar diversity, and wholesale energy market opportunities.

20 PacifiCorp's dispatchable resources have been an integral part of providing EIM

21 benefits in their ability to decrement and receive imports from the CAISO during

22 times in the day when solar production is high in California. These imports from

1 California carry the additional benefit of offsetting coal emissions and allow the
2 Company to meet its load using low-cost renewable generation.

3 **Q. Staff testifies that the TAM “filing informs the Company’s actual operations by**
4 **providing financial targets for their performance.”¹⁶ Is it true that PacifiCorp’s**
5 **actual operations are driven by the TAM forecast?**

6 A. No. PacifiCorp operates on a least cost basis and does not rely on the TAM forecast
7 as a “financial target” as Staff suggests. Importantly, each hour, day or season will be
8 significantly different than the TAM forecast due to changes in market conditions
9 such as market prices, load, hydroelectric generation, wind generation and solar
10 generation. The difference between forecast and actual conditions largely account for
11 the difference between forecast and actual NPC.

12 **A. Incremental Cost Dispatch for Off-System Sales**

13 **Q. Please describe the difference between the incremental and average cost of**
14 **production.**

15 A. The incremental cost of production is the cost required to increase the production of a
16 generation unit by one MWh. Typically, the incremental cost reflects the variable
17 costs of production and in this context is synonymous with the marginal cost. The
18 average cost of production, on the other hand, is the ratio of the total cost of
19 production to the total energy produced, which accounts for certain fixed costs in
20 addition to variable costs.

21 The testimony of Company witness Mr. David G. Webb provides additional
22 details related to the use of incremental costs in the GRID model. My testimony

¹⁶ Staff/200, Enright/10.

1 focuses on the relationship between incremental cost pricing and the Company's
2 wholesale market activities, including both bilateral and EIM transactions.

3 **Q. Why does PacifiCorp utilize the incremental cost of production and not the**
4 **average cost of production for its off-system sales?**

5 A. The average cost of production includes the cost to serve PacifiCorp's system
6 obligations, such as retail load. When an off-system sale is made, the generation
7 units required to be online to reliably serve PacifiCorp's system obligations are
8 already committed and the cost of the next MWh of energy for an off-system sale is
9 the cost to produce that next MWh of energy. Because the unit is already online, the
10 fixed costs can be viewed as previously incurred costs that are incurred regardless of
11 whether additional off-system sales are made. Therefore, if the incremental cost of
12 production is lower than the market price, then the Company can earn a margin that is
13 credited back to customers as a reduction in NPC.

14 **Q. Would NPC increase if PacifiCorp utilized the average cost of production to**
15 **price its units that are already online and economically serving retail load?**

16 A. Yes. As discussed above, if PacifiCorp determined that it was economic to serve load
17 utilizing an owned resource, versus purchasing the energy in the market, any
18 unscheduled or unused capacity can be utilized to make an off-system sale. These
19 types of sales will be priced at or above the incremental cost of energy. If the
20 incremental generation is priced at or above the average cost of energy, PacifiCorp's
21 customers will miss out on an opportunity to earn revenue towards the start-up costs
22 already incurred.

1 **Q. Sierra Club asserts that PacifiCorp made off-system sales at prices below the**
2 **average production costs of certain coal units, suggesting that the company may**
3 **be running uneconomically relative to wholesale market prices.¹⁷ How do you**
4 **respond?**

5 A. Sierra Club's comparison of the average cost of energy to the wholesale market price
6 of energy is not appropriate for determining whether an off-system sale is economic,
7 for the reasons discussed above.

8 **Q. Does Sierra Club agree that wholesale sales should be priced at the incremental**
9 **cost?**

10 A. Yes. Sierra Club agrees that it is a foundational principle of economic theory and
11 common practice in competitive markets to price wholesale sales at the incremental
12 cost of production.¹⁸ However, Sierra Club argues that the incremental cost must be
13 higher than the average cost or the firm will operate at a loss.¹⁹

14 **Q. Do you agree that the incremental cost must be higher than the average cost to**
15 **avoid operating at a loss?**

16 A. No. In addition to the points made by Mr. Webb regarding this claim, in the context
17 of *short-term* wholesale transactions, it is not the case that the incremental cost must
18 be higher than the average cost of production. Wholesale sales are made in the short-
19 term using generation units that are already required to be online in order to reliably
20 serve PacifiCorp's energy and ancillary services obligations. Consequently, Sierra

¹⁷ See, e.g., Sierra Club/100, Burgess/65-66.

¹⁸ Sierra Club/100, Burgess/36-37, lines 20-1.

¹⁹ Sierra Club/100, Burgess/37, lines 1-3.

1 Club's argument is incorrect in the short-term context of wholesale market
2 transactions in which generation resources can neither be built nor retired.

3 **Q. Does Sierra Club argue that PacifiCorp's wholesale sales should be priced at the**
4 **average cost instead of the incremental cost?**

5 A. Yes. Sierra Club argues that PacifiCorp's actual sales in both the bilateral market and
6 the EIM are improperly based on prices derived from incremental costs rather than
7 total fuel costs including fixed components.²⁰ However, PacifiCorp correctly prices
8 wholesale sales at the incremental cost of energy.

9 **Q. How does PacifiCorp bid its energy into the EIM?**

10 A. PacifiCorp bids its resources into the EIM at the incremental cost of energy. The
11 EIM is an intra-hour market whereby PacifiCorp is required to have enough energy,
12 capacity and flexibility to serve its own load each hour. Therefore, all commitment
13 decisions have been made to economically serve PacifiCorp obligations, inclusive of
14 load and reserves, and any incremental dispatch of a PacifiCorp unit in the EIM will
15 be at the incremental cost of energy. Referring to the discussion above regarding the
16 cost of energy offered for off-system sales in the wholesale market, the incremental
17 cost of energy is the appropriate bid price and should not be compared to the average
18 cost of energy.

19 **Q. Does the CAISO independently calculate a cost for each of PacifiCorp's EIM**
20 **participating generation units that is based on incremental costs?**

21 A. Yes. In the EIM the CAISO independently calculates the cost for each of
22 PacifiCorp's EIM participating generation units. This cost is referred to as the default

²⁰Sierra Club/100, Burgess/64, lines 16-21.

1 energy bid (DEB). According to CAISO's business practice manual for market
2 participants, the "purpose of the DEB is to mimic the variable cost of the generating
3 units, so that in the [EIM] generators are dispatched based on their variable costs
4 rather than their submitted Bids."²¹ Therefore, CAISO explained that the "purpose of
5 the DEB is to allow incremental dispatch based on variable cost."²² If PacifiCorp
6 were to price its EIM bids using average costs of production, as Sierra Club suggests,
7 it would run afoul of CAISO's market design.

8 **Q. Has the Commission recognized the reasonableness of using incremental**
9 **production costs for EIM bids?**

10 A. Yes. In the 2017 TAM (docket UE 307), in the context of calculating EIM benefits,
11 the Commission found that the Company's EIM bids reflected the incremental
12 production costs and that it was reasonable to calculate the EIM export benefits as the
13 difference between the bid price (i.e., the incremental production cost) and revenue
14 received.²³

15 **B. Production Costs and Market Prices**

16 **Q. Staff and Sierra Club recommend that PacifiCorp submit a report to the**
17 **Commission for all instances when actual production costs are greater than**
18 **actual market prices.²⁴ How do you respond to this recommendation?**

19 A. The Company disagrees that such a report would be useful to the Commission. First,
20 it is unclear exactly what has been requested. Staff recommends a report describing

²¹ Section D.1 of the CAISO's BPM for Market Instruments, https://bpmcm.caiso.com/BPM_Document_Library/Market_Instruments/BPM_for_Market_Instruments_V59_clean.doc.

²² Section D.1 of the CAISO's BPM for Market Instruments, https://bpmcm.caiso.com/BPM_Document_Library/Market_Instruments/BPM_for_Market_Instruments_V59_clean.doc.

²³ Order No. 16-482 at 16.

²⁴ See Staff/200, Enright/12; Sierra Club/100, Burgess/83-84.

1 when “production costs are above the market price for energy,” but it is unclear
2 whether Staff is referring to incremental or average production costs.²⁵ Sierra Club
3 also vaguely refers to “generation unit production costs” in its recommendation,
4 without clarifying whether it is referring to incremental or average production costs.²⁶

5 Second, regardless of whether the requested report is focusing on incremental
6 or average production costs, it is incorrect to claim that a unit has been
7 uneconomically dispatched simply because its production cost (whether average or
8 incremental) is higher than the market price. Mr. Webb’s testimony describes why
9 comparing the average production cost to market prices is inappropriate. My
10 testimony describes why, in actual market operations, a unit may be dispatched even
11 when its incremental production cost is higher than market prices and why such a
12 scenario is nonetheless least cost.

13 **Q. Please provide an overview of the operational considerations that govern unit**
14 **commitment and dispatch.**

15 A. PacifiCorp operates its system on a least-cost basis, which means that in any given
16 hour the incremental cost of a plant running at minimum may be higher than the
17 relative market price, but the unit must run in that hour to be available the next hour
18 for ramps in load, changes in renewable production, or other conditions. The concept
19 of production costs being greater than actual market prices is a complicated
20 discussion that must take into consideration the operational constraints of a thermal
21 unit, such as minimum on and off-times. Also, PacifiCorp does not always have an

²⁵ Staff/200, Enright/12.

²⁶ Sierra Club/100, Burgess/83,

1 opportunity to transact in the market due to reliability requirements related to
2 regulation reserves and contingency reserves. Lastly, energy products in the day-
3 ahead timeframe are typically only available in 16-hour and 8-hour blocks. This
4 means that while it may be economic to purchase in the market related to one hour, it
5 would be uneconomic to purchase in the market for the remaining 7- or 15-hours of
6 energy that PacifiCorp would be forced to take in the block transactions. PacifiCorp
7 is willing to provide additional information related to real-time operations and how
8 those compare to the TAM forecast, but a report with pre-defined parameters seems
9 short-sighted relative to all of the components that go into real-time operations.

10 **Q. Is it true that if a unit's incremental production cost is greater than the market**
11 **price there is uneconomic operations?**

12 A. No. When incremental production costs are greater than market prices this may
13 create the perception of uneconomic operations. However, this is not in and of itself
14 an indication of uneconomic operations. Efficient markets often make unit
15 commitment and economic dispatch decisions that lead to instances where
16 incremental production costs are higher than market prices when each instance is
17 looked at in isolation. However, this is merely an effect of a forward-looking, least-
18 cost dispatch solution that aims to reduce total-system NPC, rather than reduce the
19 NPC of a single generation unit.

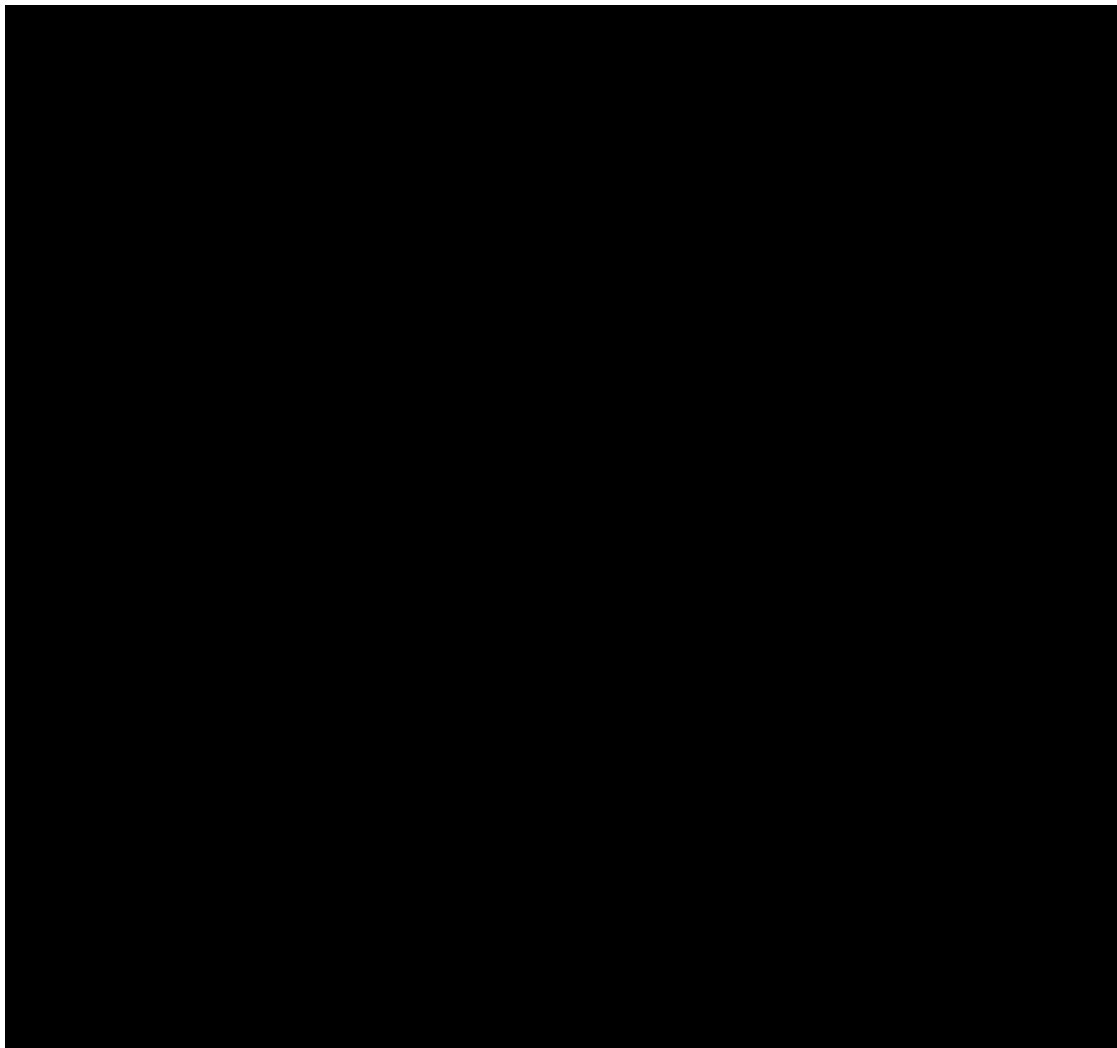
20 **Q. Please explain how unit commitment and economic dispatch decisions can create**
21 **the perception of uneconomic operations.**

22 A. In an efficient organized market with full control over unit commitment and
23 economic dispatch decisions, a unit's incremental production cost can be greater than

REDACTED

Mitchell/30

1 the market price in certain situations. This is observed today in the EIM. PacifiCorp
2 allows the EIM full control over unit commitment (the ability to startup and shutdown
3 a resource) and economic dispatch for its [REDACTED]
4 [REDACTED]. PacifiCorp has observed multiple instances in
5 which one or more of the units is committed by the EIM and the unit production cost
6 ends up higher than the market price. This is illustrated in Confidential Figure 3.
7 Furthermore, this unit [REDACTED] out of all the units in the
8 PacifiCorp system.

Confidential Figure 3

1 **Q. Why would an efficient organized market schedule a unit to operate when the**
2 **unit's incremental production cost is above the market price?**

3 A. Market conditions, such as load, wind, solar and hydroelectric output, continuously
4 change. Load, wind, solar and hydroelectric forecasts created days and hours in
5 advance are also continuously different from real-time conditions. These factors are
6 compounded by the fact that generation unit operations are limited by physical
7 characteristics such as ramp rate, minimum online time and ancillary service
8 obligations (for example, regulation reserves). Any market that determines unit
9 output is only as good as the forecasts it receives. Consequently, it is observed that
10 the production cost of online generation resources that are allowed full market
11 commitment and economic dispatch are often above real-time market prices in
12 WECC energy markets.

13 **Q. Have intervenors suggested Commission monitoring of instances in which**
14 **production costs are above market prices?**

15 A. Yes. As noted above, both Staff²⁷ and Sierra Club²⁸ suggest that the Commission
16 monitor instances in which production costs are above market prices. However, as
17 shown above, efficient market operations conducted by an organized market (the EIM
18 in this example) frequently result in situations where the production cost of online,
19 market committed units are above the market price. If this is the case in an efficient
20 and unconstrained market, then these instances do not represent uneconomic
21 operations but rather the least cost dispatch. Extending the analysis to all PacifiCorp

²⁷ Staff/200, Enright/12, lines 9-13.

²⁸ Sierra Club/100, Burgess/83-84, lines 21-3.

1 resources implies instances in which perceived uneconomic operation would be
2 indistinguishable from changing market conditions compounded by generation unit
3 characteristics that limit operational flexibility.

4 **C. Economic Cycling**

5 **Q. Please describe how the Company models its economic cycling of coal plants.**

6 A. As described in Mr. Webb's testimony, and as relevant to my testimony, the
7 Company's modeling allows coal units to cycle for economic reasons from
8 February 1 to May 31, which corresponds to the spring hydro run-off period when
9 loads are generally lower, weather is typically mild, market prices are lower, and
10 solar imports from California are increasing. The Company also precludes units from
11 economically cycling if the unit is participating in the EIM.

12 Mr. Webb's testimony provides the Company's general response to Staff's
13 proposed adjustments to modeling economic cycling. My testimony explains why the
14 Company's modeling corresponds to actual operations where it is least cost to operate
15 a unit at its minimum instead of cycling the unit.

16 **Q. Has Staff incorrectly stated the relationship between economic cycling and EIM**
17 **benefits?**

18 A. Yes. Staff asserts that low market prices and low loads in the spring incentivizes
19 economic cycling and, furthermore, that these same low market prices and low loads
20 have been identified by PacifiCorp as drivers of lower EIM benefits.²⁹ Based on this

²⁹Staff/200, Enright/15, lines 13-15.

5 A. As illustrated in Figure 4 and in prior testimony,³¹ PacifiCorp identified low market
6 prices and low loads as drivers of high EIM benefits in the spring.

PacifiCorp East Imports - Dec 2015 to Apr 2020



11 A. As a result of high EIM transfer benefits in the spring, economic cycling may provide
12 lower benefits to customers through the EIM if the energy that replaces the cycled
13 resource is not available for intra-hour re-dispatch by the EIM. Import benefits in the

³¹ PAC/200, Mitchell/8.

1 EIM can only be realized when energy from online generation is displaced by energy
2 from a lower cost resource in the EIM footprint. If the energy that replaces the cycled
3 resource is, for example, a flat, bilateral-market, block purchase, then the energy from
4 this purchase cannot be displaced in the EIM and the potential for EIM import
5 benefits is lowered.

6 Moreover, as described in more detail by Mr. Webb, the dispatch of resources
7 in actual operations is less efficient than the perfect optimization that occurs in GRID.
8 GRID's perfect foresight allows it to balance the system using market transactions
9 that cannot be used in actual operations and therefore GRID already models more
10 economic cycling than can occur in actual operations. Allowing GRID to increase
11 economic cycling will exacerbate the inherent differences between system
12 optimization modeled in GRID and system optimization that can be realized in actual
13 operations.

14 **Q. Is there an additional relationship between economic cycling and EIM benefits**
15 **that has not been identified by Staff?**

16 A. Yes. Staff has not identified the benefits of online displacement as compared to
17 economic cycling. Import benefits in the EIM can only be realized when energy from
18 online generation is displaced by energy from a lower cost resource in the EIM
19 footprint. In years past, the argument for economic cycling of generation resources
20 relied primarily on the economic benefits of replacing the entire resources' output
21 with cheaper energy from the marketplace. However, high startup/shutdown costs
22 have always been one of the driving forces that limited the economic benefits of this
23 type of operation. Now that PacifiCorp is able to reduce minimum generation levels

REDACTED

1 to an all-time low (for example, minimum generation levels of ■ MWh at Naughton
2 Unit 1 and ■ MWh at Jim Bridger Unit 2) it is now most often the case that the least
3 cost approach to serving customer's load is to have the energy from online generation
4 resources displaced by the intra-hour, automated, least-cost dispatch solutions
5 produced by the EIM. In this paradigm the generation resources are brought down to
6 their minimum generation levels in real-time while remaining online and high
7 startup/shutdown costs are avoided. These practices are now an operational reality as
8 low-cost energy from across the west is made available to PacifiCorp through the
9 EIM.

10 **Q. Are the benefits to online displacement comparable to the benefits from**
11 **economic cycling?**

12 A. Yes, although the benefits of online displacement are likely greater. With online
13 displacement, load is served more reliably as the generation resources remain online
14 and ready to respond to system balancing, frequency, and contingency events that
15 may arise. Additionally, unexpected real-time deviations in load, wind, solar and
16 hydroelectric generation across the WECC create real-time market opportunities for
17 wholesale transactions that directly reduce NPC. These opportunities can only be
18 realized if generation resources are online and capable of increasing or decreasing
19 output as necessary. Additional benefits to online displacement as compared to
20 economic cycling are the avoidance of expenses associated with startups/shutdowns,
21 the reduction in variable operation and maintenance costs as energy is displaced and
22 the reduction of carbon emissions and pollution control costs identified by Staff.³²

³² Staff/200, Enright/19, lines 20-22.

1 **Q. Both Staff³³ and Sierra Club³⁴ refer to articles where utilities that operate in**
2 **organized wholesale markets have been urged to change their self-commitment**
3 **practices to decrease coal plant dispatch in response to the evolving utility**
4 **landscape. Are there differences between PacifiCorp and utilities operating in**
5 **organized markets that renders Staff's and Sierra Club's comparison inapt?**

6 A. Yes. PacifiCorp is differently situated than the utilities Staff and Sierra Club refer to
7 because PacifiCorp is a Balancing Authority (BA) and therefore carries additional
8 responsibilities that must be considered when making self-commitments.

9 **Q. What is a BA?**

10 A. A BA is an entity which supports WECC frequency and ensures, in real-time, that an
11 area's demand and supply are in equilibrium (balance). This balance is needed to
12 maintain the safe and reliable operation of the power system. If demand and supply
13 fall out of balance, local or even wide-area blackouts can result.³⁵ PacifiCorp is a
14 BA. Other examples of BAs include Midcontinent Independent System Operator
15 (MISO), Pennsylvania, Jersey, Maryland Power Pool (PJM), the Southwest Power
16 Pool (SPP) and the Electric Reliability Council of Texas.

17 **Q. What is a BAA?**

18 A. A BAA is the geographical/electrical region that is managed by a BA. Specifically, it
19 is the geographical/electrical region that is managed by an entity which supports
20 WECC frequency and ensures, in real-time, that the area's demand and supply are in

³³ Staff/200, Enright/6, lines 6-8.

³⁴ Sierra Club/100, Burgess/69, lines 15-20.

³⁵ <https://www.eia.gov/todayinenergy/detail.php?id=27152>.

1 balance. For example, PacifiCorp is a BA responsible for two BAAs: PACW and
2 PACE.

3 **Q. What is a self-commitment?**

4 A. A self-commitment decision refers to the starting up and shutting down of resources.

5 **Q. How do commitment decisions made by a BA differ from commitment decisions**
6 **made by utilities that have no BA responsibilities?**

7 A. Balancing authorities like PacifiCorp, MISO, PJM, SPP, etc. have to make
8 commitment decisions that ensure there is sufficient energy to serve load and
9 sufficient generation online to support WECC frequency and to respond to
10 unexpected changes in demand and supply. These unexpected changes require the
11 real-time deployment of ancillary services such as regulation reserves, frequency
12 responsive reserves, and spinning reserves.

13 Utilities with no BA responsibilities like Xcel Energy Minnesota, the Texas
14 Municipal Power Agency, Umatilla Electric Cooperative, Eugene Water and Electric
15 Board, etc. need only to ensure that they have sufficient energy to serve load. This
16 energy does not need to come from online, responsive generation resources because
17 their BA will ensure that their system is reliably operated.

18 **Q. How do PacifiCorp's additional BA responsibilities impact its self-commitment**
19 **decisions?**

20 A. PacifiCorp's obligations to ensure system reliability in addition to serving retail load
21 means that it must consider additional factors when deciding whether to shut down a
22 coal unit. Without the backstop of an external BA with an organized day-ahead

1 market, like MISO, PacifiCorp must consider more than just expected market prices
2 when determining unit commitment, as described in more detail by Mr. Webb.

3 **Q. Does PacifiCorp's participation in the EIM, which is a form of an organized**
4 **market, create a potential for the Company to overschedule its coal units, as**
5 **Sierra Club suggests?**³⁶

6 A. No. PacifiCorp's scheduling practices in the EIM tells the market if generation is
7 available for intra-hour optimization but cannot force a unit to run above its minimum
8 operating level. In short, PacifiCorp's scheduling practices cannot force the EIM to
9 accept generation from its coal units in the same way Sierra Club claims utilities in
10 fully organized markets can.

11 **Q. Does this conclude your reply testimony?**

12 A. Yes.

³⁶ Sierra Club/100, Burgess/69-70.

Docket No. UE 375
Exhibit PAC/901
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

2020 CAISO EIM Benefit Methodology Reply Filing

June 2020

EIM Quarterly Benefit Report Methodology

Effective with Q1 2020 EIM benefits report

Prior to the creation of this document, the methodology for the benefits calculation was posted in a technical bulletin and in the benefit report itself. This document consolidates these prior materials into a concise paper for easier understanding of how the EIM benefits are calculated.

The total EIM benefit is the cost saving of the EIM dispatch compared with a counterfactual (CF) without EIM dispatch. The counterfactual dispatch meets the same amount of real-time load imbalance in each BAA without EIM transfers between neighboring EIM BAAs. For an EIM BAA, the benefit can take the form of cost savings or profit or their combination. A BAA will be likely to have energy cost savings when the BAA is importing energy economically, or its base schedules are being optimized by the EIM. To the extent an entity base schedule is optimized prior its submission into the EIM, the benefits may be lessened when compared to an entity that has not submitted optimized base schedules into the EIM. A BAA will be likely to have an energy profit when the BAA is exporting energy economically to other BAAs and being paid a price higher than the bid cost. A BAA other than the ISO may also have a GHG profit when the resource is allocated GHG MWs and is receiving GHG revenue based on marginal GHG cost that is likely higher than its own GHG bid cost.

For each 5-minute interval, the **EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost**. The 5-minute level EIM benefits are then aggregated each month with a multiplier 1/12 to convert (\$/5 min) to a dollar amount.

EIM Benefit Calculation Components

EIM Dispatch Cost

The total dispatch cost for a BAA for an interval is the sum of all the unit level EIM dispatch costs for that BAA for that interval.

For all BAAs other than CAISO, the dispatch cost only includes variable dispatch cost, i.e. the bids submitted by the corresponding Scheduling Coordinator.

For the ISO's long start units, we only consider variable dispatch cost. For the ISO's short start units, we use a generic cost formula, which includes variable dispatch cost, no load cost, and startup cost. Specifically, the three-part cost for short start units includes:

- The variable dispatch cost of RTD, which is equal to the bid cost associated with the delta instruction above or below the base schedule for each interval,
- the no load cost associated with the incremental dispatch, which is equal to the no load cost divided by Pmax, then multiplied by the delta instruction from the base schedule,
- The startup cost associated with the incremental dispatch, which is equal to the startup cost divided by the minimum online hours, then multiplied by the delta instruction from base schedule divided by the Pmax.

The purpose of this generic cost formula is to evaluate cost differences between EIM dispatches and counterfactual dispatches without performing sophisticated unit commitment simulations. Prior to Q1 2016, only variable dispatch cost was considered in the EIM benefit calculation. With NV Energy joining EIM and improving the transfer capabilities from and to the ISO, we observed a significantly increased transfer volume in EIM. The higher transfer volume cannot be sufficiently replaced by resources online in EIM without committing or de-committing resources, and hence the ISO adopted a three-part cost formula as of Q1 2016 to allow for unit commitment decisions to better evaluate the production difference between EIM and the counterfactual dispatch of the ISO. The unit commitment decisions were made only for short start units that were not combined cycle units. The combined cycle units have complicated models in EIM, so their counterfactual commitment status is fixed at the EIM commitment status to avoid oversimplification.

We approximate the ISO's commitment costs by converting the startup cost and no load cost into variable dispatch cost, assuming a committed short start resource will be fully loaded for minimum online hours. For each supply segment, the corresponding three-part variable cost is equal to

$$\text{bid_price} + \text{no_load_cost}/P_{\text{max}} + \text{startup_cost}/\text{min_up_hour}/P_{\text{max}}$$

Note the formula above converts startup cost (in unit \$) and no load cost (in unit \$/h) into variable dispatch cost (in unit \$/MWh). By doing this, the commitment for the ISO's short start units can be determined based on the economic metric order of the three-part variable cost.

Transfer Cost

As a convention, select the importing direction as the default direction for a transfer, so the importing transfer is positive and the exporting transfer is negative. The transfer cost is equal to the transfer MW times the transfer price. For transfers involving the ISO in either the importing direction or the exporting direction, the transfer price is the other BAA's LMP plus the shadow price of the transfer. In doing this, the congestion rent on the transfer will be fully attributed to the other BAA. For transfers involving two BAAs that are not the ISO, the transfer price will split the congestion shadow price on the transfer in half. For an importing BAA, the transfer price is the LMP of the BAA minus half of the absolute value of the transfer shadow price. For an exporting BAA, the transfer price is the LMP of the BAA plus half of the absolute value of the transfer shadow price. The transfer could occur in both the 15-minute market and the 5-minute market. In this case, the transfer cost is 15-minute transfer * 15-minute transfer price + (5-minute transfer – 15-minute transfer) * 5-minute transfer price for each 5-minute interval.

Flex Ramp Transfer Cost

In 2016, the ISO implemented the flexible ramping products to replace flexible ramping constraints. The flexible ramping products are available capacities to handle future load and generation uncertainties, and include both the upward ramping capacity and downward ramping capacity. They may be put aside in RTD to enhance dispatch flexibility. One BAA's flexible ramping capacities in RTD may be helping other BAAs. In this case, the BAA that exports flexible ramping products should receive payment from other BAAs to compensate the dispatch

cost of keeping flexible ramping capacities, and the BAA that imports flexible ramping products should pay other BAAs to reflect its dispatch cost to handle future uncertainties. This is similar to how energy transfer is treated in the EIM benefit calculation. Energy transfer is explicitly modeled in EIM, while flexible ramping transfer is not. We need to calculate a BAA's flexible ramping transfer. First, we allocate the system flex ramp award to each BAA in proportion to its individual BAA requirement. Then we calculate the flex ramp transfer as the BAA's RTD flexible ramping award minus its allocated share. The flex ramp transfer cost is equal to the flex ramp transfer multiplied by the EIM whole footprint flex ramp shadow price.

Counterfactual Dispatch Cost

The counterfactual dispatch for an EIM BAA mimics the market operations without importing or exporting through the EIM transfers. The counterfactual dispatch moves units inside the BAA to meet the same real-time load imbalance as the EIM dispatch based on economic merit order without considering transmission constraints. For PacifiCorp, the transfer limit between PACE and PACW is enforced in the counterfactual dispatch.

Neglecting transmission constraints in a BAA tends to underestimate the EIM benefit. The magnitude depends on how significant the congestion is. Severe congestion impacting EIM benefits was not observed until October 2017, where transmission congestion happened between the generation in Wyoming and PACE's load in PacifiCorp. The impact of this congestion to the EIM benefit calculation can be demonstrated with the following example.

Assume in PACE, load increased 10 MW from the base schedule, generation decreased 100 MW from the base schedule, and PACE imported 110 MW in EIM. Note that energy is balanced in PACE with 110 MW of transfer import replacing 100 MW of generation and serving 10 MW of load above the base schedule. Assume the decremented generation cost is \$20/MWh, and the import cost is \$120/MWh. From an economic standpoint, the EIM dispatched the resources out-of-merit with high cost supply being incremented and low cost supply being decremented. If we were to calculate the EIM benefit ignoring the congestion effect, the benefit will be negative. The calculation is as follows:

$$\text{EIM dispatch cost} = -100 \text{ MW} * \$20 = -\$2,000.$$

$$\text{EIM transfer cost} = 110 \text{ MW} * \$120 = \$13,200.$$

$$\text{Counterfactual dispatch cost} = 10 \text{ MW} * \$20 = \$200.$$

$$\text{For simplicity, ignore flex ramp and GHG. The EIM benefit is calculated as } \$200 - (-\$2,000 + \$13,200) = -\$11,000.$$

To better understand the root cause of the negative benefit, we break the calculated benefit into two components: infeasible base schedule and infeasible counterfactual.

1. Infeasible base schedule: In the EIM, the imported \$120 transfer replaced 100 MW of \$20 internal generation, and produced a negative benefit equal to $100 * (\$20 - \$120) = -\$10,000$. The extra dispatch cost in EIM is not due to economics, but due to infeasible base schedules for

certain constraints, which forces the EIM to mitigate congestion, and incurs additional cost. For this reason, we need to add the congestion management cost to the counterfactual dispatch cost to reflect the need to perform the same congestion management dispatch as in the EIM. In the example, we add \$10,000 to the counterfactual dispatch cost.

2. Infeasible counterfactual: In the counterfactual, the merit order dispatch did not know that dispatching up the \$20 generation would overload the transmission, and produced a negative benefit equal to $10 * (\$20 - \$120) = -\$1,000$. The counterfactual should recognize the economic \$20 supply is subject to transmission congestion, and cannot be dispatched. Therefore, in the counterfactual dispatch, for increased net load, we dispatch only supply offers with a bid price \geq the transfer LMP. For decreased net load, we dispatch down only supply offers with a bid price \leq the transfer LMP. In the example, the net load is 10 MW, so we only dispatch resources that bid above \$120, assume these supplies cost \$125/MWh.

With these two enhancements, we revise the benefit calculation as follows:

$$\text{EIM dispatch cost} = -100 \text{ MW} * \$20 = -\$2,000.$$

$$\text{EIM transfer cost} = 110 \text{ MW} * \$120 = \$13,200.$$

$$\text{Counterfactual dispatch cost} = 10 \text{ MW} * \$125 + \$10,000 = \$11,250.$$

$$\text{The new EIM benefit is calculated to be } \$11,250 - (-\$2,000 + \$13,200) = \$50.$$

These enhancements only apply when we detect significant congestion indicated by the LMP difference between the BA's ELAP and DGAP greater than a tolerance setting. Currently, the tolerance is set to \$5/MWh.

The counterfactual dispatch makes unit commitment decisions only for the ISO's short start units. The unit commitment decisions are based on the generic three-part variable cost formula, which has converted startup cost and no load cost into variable dispatch cost, so unit commitment can be determined by the economic metric order of the three-part cost.

Prior to the 2016 Q4 report, we used the resources' RTD dispatching limits from the EIM in the counterfactual. The EIM dispatching limits are 10-minute ramp limited in RTD, and they may be overly constraining for the counterfactual theoretically. The counterfactual will replace the transfers with internal dispatches, but it does not need to do it within 10-minute timeframe. When EIM transfer volumes are moderate relative to the EIM dispatching range, this limitation may not be a real problem, because the EIM dispatch range is mostly sufficient to replace the transfers. As the EIM footprint increases, the transfer volume between BAAs also increases. We observed that some EIM transfers exceeded 1,000 MW frequently. The EIM dispatching range started to show its limitation. In Q4 of 2016, we expanded the resources' dispatching range to base schedule and FMM dispatching limits. From Q2 of 2017, we decided not to use EIM calculated limits. Instead, the dispatching range is constructed based on the resource's economic bid range in the following way:

- a) Start with the resource's bid range [bid_MW_min, bid_MW_max]

- b) Block the ancillary service provisions, so the new range is $[\text{bid_MW_min} + \text{reg_down}, \text{bid_MW_max} - \text{reg_up} - \text{spin} - \text{nonspin}]$
- c) If the resource is a wind or solar resource, limit its upper limit by the forecasted output, so the new range is $[\text{bid_MW_min} + \text{reg_down}, \min(\text{bid_MW_max} - \text{reg_up} - \text{spin} - \text{nonspin}, \text{wind or solar forecast})]$

In cases where a counterfactual dispatch does not have sufficient supply offers to meet net load imbalance, we assign a penalty cost for procuring more energy. If the BA does not import from EIM, we extend its last economic bid segment. If the BA imports from EIM, we compare its last economic segment against the EIM LMP, and set the penalty price to the higher of the two. In summary, the penalty price per MWh is

- The highest offer price from the BA if the BA does not import from EIM,
- Max (the highest offer price from the BA, the transfer LMP) if the BA imports from EIM.

An EIM BAA may restrict the pool of dispatchable units in the counterfactual dispatch if that the BAA's practice prior to joining EIM was to balance real-time load from a limited pool.

ISO Counterfactual Dispatch

The ISO would need to meet load without EIM transfers in the counterfactual dispatch. The counterfactual dispatch is constructed in the following way:

1. Calculate the ISO's net EIM transfer;
2. Economically dispatch resources from the ISO to replace the transfer
 - A. If the ISO is importing from the EIM,
 - a. Find the ISO's undischatched supply with the variable cost (bid and three-part converted) greater than or equal to the reference transfer price;
 - b. Sort and stack the supply by the variable cost from low cost to high cost; and
 - c. Clear the supply stack from low cost to high cost up to the transfer megawatts
 - B. If the ISO is exporting to the EIM,
 - a. Find the ISO's dispatched supply with the variable cost (bid and three-part converted) less than or equal to the reference FMM transfer price;
 - b. Sort and stack them by the variable cost from high cost to low cost; and
 - c. Clear the supply stack from high cost to low cost up to the transfer megawatts

The reference transfer price for the ISO is the maximum price of the incoming transfer points if the ISO is a net transfer importer, and the minimum price of the outgoing transfer points if the ISO is a net transfer exporter in RTD. Undischatched supply at lower bid cost than the reference price is dispatched out of merit when the ISO is importing transfer at the reference price. Dispatched supply at higher bid cost than the reference price is also dispatched out of merit when the ISO is exporting transfer at the reference price. The ISO has complex networks and constraints that are modeled in the EIM but not in the counterfactual. For example, supplies can be locally transmission constrained and undischatched in the EIM, which have available supply at lower bid cost than the LMP of the rest of the ISO. They should remain undischatched in the counterfactual even they have lower supply cost, because they are constrained by transmission. In the ISO's counterfactual dispatch, we only consider supplies above the reference transfer price to replace incoming transfer into the ISO, and thus preventing the transmission constrained lower cost supply being dispatched. Vice versa for the supplies below the reference

transfer price to replace outgoing transfer. The counterfactual dispatch (applies for whole EIM, not just the ISO) was based on 5-minute dispatch capability, and the reference price is the RTD price.

Counterfactual Dispatch

All EIM entities, with the exception of PacifiCorp, have their counterfactual dispatch constructed in the following way. We will use NVE as an example.

1. Calculate the real-time net load imbalance for NVE;
2. Economically dispatch resources from NVE on top of the base schedules to meet NVE's net load imbalance
 - A. If the net load imbalance is positive,
 - a. Dispatch NV Energy's bid-in supply above base schedules;
 - b. Sort and stack them by the variable cost from low cost to high cost; and
 - c. Clear the supply stack from low cost to high cost up to the net load imbalance.
 - B. If the net load imbalance is negative,
 - a. Dispatch NV Energy's bid-in supply below base schedules;
 - b. Sort and stack them by the variable cost from high cost to low cost; and
 - c. Clear the supply stack from high cost to low cost up to the net load imbalance.

PacifiCorp Counterfactual Dispatch

PacifiCorp East BAA and PacifiCorp West BAA would need to meet demand without intra-hour transfers between PacifiCorp and the ISO, but transfers could occur between PACE and PACW in the counterfactual dispatch. The PacifiCorp counterfactual dispatch will be constructed in the following way:

1. Calculate the real-time net load imbalance for each BAA;
2. Economically dispatch resources from PacifiCorp on top of the base schedules to meet net PacifiCorp load imbalance without violating the transfer limitations between PACE and PACW.
 - A. If the net load imbalance is positive,
 - a. Find PacifiCorp's bid-in supply above base schedules;
 - b. Sort and stack them by the variable cost from low cost to high cost; and
 - c. Clear the supply stack from low cost to high cost up to the net load imbalance subject to the transfer limit between PACE and PACW
 - B. If the net load imbalance is negative,
 - a. Find PacifiCorp's bid-in supply below base schedules;
 - b. Sort and stack them by the variable cost from high cost to low cost; and
 - c. Clear the supply stack from high cost to low cost up to the net load imbalance subject to the transfer limit between PACE and PACW

GHG Revenue

Greenhouse gas (GHG) revenue for a resource is equal to its GHG allocation MW times the GHG price.

GHG Cost

GHG cost for a resource is equal to its GHG allocation MW times its GHG bid.

Example

This example illustrates how the EIM benefit is calculated.

The transfers out of the EIM optimization are listed in Table 1. Base scheduled transfers have been excluded in the FMM transfers and RTD transfers.

From BAA	To BAA	FMM transfer	FMM transfer price	RTD incremental transfer	RTD transfer price	Transfer cost
PACE	NEVP	140	\$26	10	\$25	\$3,890
NEVP	CISO	160	\$26	20	\$30	\$4,760
PACE	PACW	190	\$26	10	\$25	\$5,190
PACW	CISO	110	\$26	-10	\$30	\$2,560

Table 1. An example of BAA to BAA transfers and prices

Assume the EIM energy imbalance and prices are as follows. Every BAA is balanced with $\text{Gen} + \text{Transfer} - \text{Load} = 0$. Assume the EIM optimization results in \$1 GHG price, which means the ISO's LMP is \$1 higher than the neighboring BAA (NEVP and PACW), because there is no congestion going into the ISO in the example. In the table below, positive transfer MW means the BAA is importing and negative transfer MW means it is exporting. Also, transfers in the table are sum of the transfers occur in both the FMM and the RTD with base scheduled transfer being excluded.

BAA	Gen	Load	Net transfer in MW	LMP	GHG price
CISO	0	280	280	\$31	\$1
NEVP	50	20	-30	\$30	
PACE	150	-200	-350	\$20	
PACW	100	200	100	\$30	

Table 2. EIM energy imbalance and prices by BAA for one 5-minute interval

Transfer Cost

The transfers occur in both FMM and RTD, and their volume and prices are listed in Table 3. They are calculated from applying the convention that importing is positive and exporting is negative the BAA to BAA transfers, and summing them over all the neighboring BAAs.

BAA	transfer cost
CISO	$\$7,320 = \$4,760 + \$2,560$
NEVP	$(\$870) = \$3,890 - \$4,760$
PACE	$(\$9,080) = -\$3,890 - \$5,190$
PACW	$\$2,630 = \$5,190 - \$2,560$

Table 3. EIM transfer cost by BAA

For flex ramp, we calculate its transfer and transfer cost in Table 4.

BAA	Direction	Req.	Award	Allocation	Flex ramp transfer in	Flex ramp price	Flex ramp transfer cost
CISO	upward	150	100	75	-25	\$1	-\$25
NEVP	upward	10	0	5	5	\$1	\$5
PACE	upward	20	0	10	10	\$1	\$10
PACW	upward	20	0	10	10	\$1	\$10
CISO	downward	0	0	0	0	\$2	\$0
NEVP	downward	10	10	2	-8	\$2	-\$16
PACE	downward	20	0	4	4	\$2	\$8
PACW	downward	20	0	4	4	\$2	\$8

Table 4. Flex ramp transfer example

EIM Dispatch Cost

Now calculate the total bid cost associated with the EIM dispatches (delta from base schedules). The EIM dispatch costs are listed in Table 5.

BAA	Gen_EIM	EIM dispatch cost
CISO	0	\$0
NEVP	50	\$1,450
PACE	150	\$2,700
PACW	100	\$2,800

Table 5. EIM dispatch cost by BAA

Counterfactual Dispatch Cost

Then construct the counterfactual dispatches as described in the previous section, and sum up the counterfactual dispatch cost for each BAA as shown in Table 6.

BAA	Gen_CF	Counterfactual dispatch cost
CISO	280	\$9,240
NEVP	20	\$640
PACE	-200	(\$3,800)
PACW	200	\$6,200

Table 6. Counterfactual dispatch cost by BAA

GHG Cost and Revenue

The GHG costs associated with the 280 MW of importing transfer into CISO, and the revenues received by the GHG allocated MWs in both FMM and RTD are listed in Table 7.

BAA	GHG FMM MW	GHG RTD MW	GHG cost	GHG revenue
CISO	270	280	\$0	-\$280
NEVP	0	0	\$0	\$0
PACE	200	200	\$20	\$200
PACW	70	80	\$75	\$80

Table 7. GHG cost and revenue by BAA

EIM Benefit

With all the cost and revenue for each BAA available, we can use the formula EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost to calculate EIM benefit for each BAA. The results are shown in Table 8.

BAA	CF dispatch cost	EIM dispatch cost	Transfer cost	Flex transfer cost	GHG cost	GHG revenue	EIM benefit
CISO	\$9,240	\$0	\$7,320	(\$25)	\$0	(\$280)	\$1,665
NEVP	\$640	\$1,450	(\$870)	(\$11)	\$0	\$0	\$71
PACE	(\$3,800)	\$2,700	(\$9,080)	\$18	\$20	\$200	\$2,742
PAC W	\$6,200	\$2,800	\$2,630	\$18	\$75	\$80	\$757

Table 8. EIM benefit for one 5-minute interval

This calculation is performed for each 5-minute interval with unit \$/hr. We convert the \$/hr benefit into the dollar benefit by multiplying 1/12. Then the 5-minute interval benefits in dollar amount can be aggregated into the monthly benefit by summing all the 5-minute intervals in the month.

Docket No. UE 375
Exhibit PAC/902
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

2020 Colorado EIM Entrants Reply Filing

June 2020

WESTERN ENERGY IMBALANCE MARKET



California ISO

News Release

For immediate release | **May 21, 2020**

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Four Colorado utilities to join the West's real-time energy market

The Western EIM will serve over 80 percent of WECC's total load by 2022

FOLSOM, Calif. – The California Independent System Operator (ISO) has signed an implementation agreement with Xcel Energy - Colorado paving the way for its participation in the Western Energy Imbalance Market (EIM) in 2022.

The agreement also provides for participation of the other Joint Dispatch Agreement (JDA) members: Black Hills Energy Colorado Electric, Colorado Springs Utilities, and Platte River Power Authority.

“The addition of these Colorado utilities to a growing west wide market will benefit all of the participants and their customers,” said ISO President and CEO Steve Berberich.

“We are pleased the Xcel Energy - Colorado and its other JDA partners have confidence in the market which shares carbon-free energy resources, market efficiency and enhanced reliability.”

“We are excited to take the next step in joining the Western Energy Imbalance Market,” said Alice Jackson, president of Xcel Energy - Colorado. “Participating in this market will support our efforts to keep customer bills low while providing them with more 100% carbon-free energy from wind and solar resources. That’s both a win for the environment and another way we can help the State of Colorado meet its clean energy goals.”

Xcel Energy - Colorado’s implementation agreement with the ISO will support the four utilities as they transition from the JDA to participation in the Western EIM. During the transition, the ISO will work with the JDA partners to provide resource schedules, load forecasts, and outage reporting directly to the ISO. Additionally, settlement documentation for each of the entities load and resources will be developed by the ISO for each of the JDA partners. While developing the details of the working relationship for Xcel Energy – Colorado and the other three JDA parties, the ISO plans to conduct a stakeholder process to develop the tariff modifications to make these provisions available to other entities.

Since its launch five years ago, the Western EIM has provided \$919.79 million in gross benefits to its participants. Because of the regional cooperation, consumers in the Western EIM have used 1,098,890 MWh of renewable energy, which is equivalent to the annual electric use of 140,000 homes in California.

And due to the increased carbon-free energy consumption, CO₂ emissions were reduced by 470,245 metric tons, or the equivalent of 98,867 passenger cars.

With the addition of Xcel Energy - Colorado, the Western EIM will consist of 21 balancing areas and represent 82 percent of the Western Electricity Coordinating Council's (WECC) total load by 2022.

The Western EIM's active participants include the ISO, PacifiCorp, NV Energy, Arizona Public Service, Puget Sound Energy, Portland General Electric, Idaho Power, Powerex, Balancing Authority of Northern California (BANC) Phase 1, Seattle City Light and Salt River Project.

Over the next two years, the Western EIM's expansion will continue, with the addition of the Los Angeles Department of Water and Power, NorthWestern Energy, Turlock Irrigation District, Public Service Company of New Mexico, and BANC Phase 2 in 2021; and Tucson Electric Power, Avista, Tacoma Power, Bonneville Power Administration, and Xcel Energy - Colorado in 2022.

For more information, visit www.westerneim.com

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<p>The California ISO provides open and non-discriminatory access to one of the largest power grids in the world. The vast network of high-voltage transmission power lines is supported by a competitive energy market and comprehensive grid planning. Partnering with about a hundred clients, the nonprofit public benefit corporation is dedicated to the continual development and reliable operation of a modern grid that operates for the benefit of consumers. Recognizing the importance of the global climate challenge, the ISO is at the forefront of integrating renewable power and advanced technologies that will help meet a sustainable energy future efficiently and cleanly.</p>	

Docket No. UE 375
Exhibit PAC/903
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

2020 Flexible Ramping Product Reply Filing

June 2020



Flexible Ramping Product Refinements

Issue Paper and Straw Proposal

November 14, 2019

Flexible Ramping Product Refinements

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1. Purpose

This paper summarizes the flexible ramping product issues identified in the CAISO Energy Markets Price Performance Report¹ published on September 23, 2019. The flexible ramping product² was introduced in to the real-time market to manage ramp capability to address uncertainty related to load and variable energy resources that materializes between market runs. Prior to implementation, the CAISO observed that the multi-interval market optimization would solve forecasted net load by utilizing the precise amount of ramp needed across the market horizon. However, when system conditions changed in subsequent market runs, the market would have insufficient ramping capability in the real-time dispatch. The flexible ramping product secures additional ramping capability that can be dispatched in subsequent market runs to cover a range in the forecasted net load. Resources providing this ramping capability are compensated at the marginal opportunity cost for both forecasted movement and uncertainty awards.

The report identified four areas that needed to be addressed through BPM and/or tariff changes. The issues include the following:

Issue	BPM or Tariff Change	Targeted Implementation
Proxy Demand Response Eligibility	BPM only	Fall 2019
Ramp Management between FMM and RTD	BPM only	Fall 2020
Minimum CAISO FRP requirement	BPM only	Fall 2020
Deliverability Enhancement	Both	Fall 2021

As noted above the first three items can be addressed in the near term. The paper discusses the proposed BPM changes. The specific BPM language will be developed through the BPM change management process. For deliverability, the paper discusses the issues and different approaches to minimize procurement of flexible ramping product that is stranded due to transmission constraints within balancing authority areas.

2. Proxy Demand Response Eligibility

Flexible ramping products can be awarded to multiple types of resources, including proxy demand resources (PDR). Recent trends show the market frequently awards flexible ramping product to PDR resources because they have energy bids at or close to the bid cap of \$1,000/MWh. This occurs because the market sees them as economic to provide the upward flexible ramping product because their opportunity cost of providing the flexible ramping product is zero because the PDR is not economic to be dispatched for energy in the binding market interval.

¹ The report is available at <http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf>

² Information on the flexible ramping product design is available at <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=24AB06E3-B018-4DEC-8F43-28B8A0E90514>

This issue is currently exacerbated because many PDRs cannot respond to the 5-minute dispatch despite the flexible ramping product capacity being needed in the 5-minute dispatch. Despite this inability to respond to 5-minute dispatches, the CAISO's current market rules assume all PDRs can respond to 5-minute dispatches. If PDRs are unable to respond to five-minute real-time dispatches, the procured flexible ramping product cannot be used as energy in a subsequent RTD run.

In the *Energy Storage and Distributed Energy Resources Phase 3A* initiative, additional bidding options were made available to PDRs. These include a 60-minute and 15-minute dispatchable bid option. Unlike the 5-minute dispatch which has a 2.5 minute notification to curtail load, these options provide 22.5 minutes and 52.5 minutes notification prior to the time load needs to be curtailed. Consistent with newly FERC-approved provisions in section 4.13.3 of the CAISO tariff, PDRs will be able to specify in the Master File how the PDR will bid and be dispatched in the real-time market: in (i) hourly blocks, (ii) fifteen minute intervals, or (iii) five minute intervals. If PDRs do not select an option the CAISO will set five minute intervals as the default. These provisions are effective as of November 13, 2019. Consistent with existing section 4.6.4, Master File must be an accurate reflect of the design capabilities of the resources. Therefore, scheduling coordinators will be required to ensure their Master File designation appropriately reflects their PDR capabilities and if they do not have the ability to respond to five minute dispatch, the scheduling coordinator should designate their resource as hourly blocks or 15-minute dispatchable. Consistent with section 44.2.3.1, the 15-minute and 60-minute options will not be eligible to be awarded the flexible ramping products. The CAISO will develop a business process to validate that the PDR has selected the correct scheduling/dispatch options. This will address the issue that flexible ramping product is awarded to PDRs that are unable to respond to the 5-minute dispatch.

3. Ramp Management between FMM and RTD

The CAISO procures the flexible ramping product in both the 15-minute market (FMM) and the 5-minute real-time dispatch (RTD). In the FMM, the flexible ramping product covers the uncertainty between the advisory FMM interval and the highest/lowest binding RTD interval for the same 15-minute time interval. This ensures that there is sufficient ramp capability committed to clear RTD.

The FMM is part of the real-time unit commitment (RTUC) process. The RTUC runs every fifteen minutes to determine binding unit commitment decisions for fast and short start units within the RTUC horizon. The RTUC horizon is the next four to seven fifteen-minute intervals, depending on when during the hour the run occurs. The second interval of each RTUC run horizon is designated as the FMM and is the financially binding interval for energy prices and schedules used for settlements. The first interval in an RTUC run horizon, or the interval preceding FMM, is referred to as the buffer interval. The logic of the buffer interval was introduced in the market with the implementation of the FERC Order No. 764 in order to provide sufficient time for tagging purposes once fifteen-minute interties could economically participate in the real-time market. The buffer interval can issue binding unit commitment of fast and short start units. The buffer interval also produces advisory schedules and prices that are not financially binding. The remaining intervals in the horizon can also issue binding unit commitments and also produce advisory schedules and prices.

Currently, the flexible ramping product uncertainty requirement is not enforced in the buffer interval. As a result, the ramping capability procured in the prior RTUC run, when the time interval was financially binding (FMM), may be used to meet the ramping needs of the current market run. When system conditions change between FMM runs there may no longer be any ramping capability available for the RTD intervals within that timeframe; or, even worse, the ramping capability may be lost. Ramping capability is lost when projected start-ups of certain units necessary to carry flexible ramping product are re-optimized in subsequent intervals and no longer determined as needed because of additional ramping capability resulting from the release of the flexible ramping product from the buffer interval to the binding interval.

The CAISO proposes to maintain a portion, up to 100%, of the FRP awards in the buffer interval that were procured in the prior FMM. This will ensure that ramping capability will be preserved for RTD. This can result in a resource not being scheduled in the FMM interval because its ramping capability was secured through a flexible ramping product award in the previous market run. For example, assume a resource with the following characteristics: $P_{min} = 100$ MW, $P_{max} = 200$ MW, and a ramp rate of 5 MW/Minute. In market run #1, the resource receives a binding commitment in FMM and is scheduled for energy at 100 MW and awarded flexible ramping up of 75 MW. In market run #2, if the flexible ramping product requirement is not enforced in the buffer interval, the resource could receive an energy schedule of up to 175 MW in the FMM. However, if the flexible ramping product is enforced in the buffer interval, the resource could receive an energy schedule of up to 125 MW because the 75 MW flexible ramping up award is maintained.

4. Minimum FRP requirement for CAISO

The net import/export capabilities (NIC/NEC) are used as a credit towards a balancing authority area's requirement. The basic idea is that flexible ramping awards can be supplied from other balancing authority areas through the import or export transfer capability. The CAISO has previously found³ that credits on imports and exports were beyond levels that a balancing authority area could feasibly support. As a result, in 2018, the CAISO made an enhancement to limit the amount of flexible ramping product that could be awarded in a balancing authority area to that which could be supported given the import/export transfer capability. With this enhancement, the market can schedule flexible ramping product in a balancing authority area up to the amount of the remaining transfer capacity, thereby making use of any remaining import/export capability but not exceed the amount the balancing authority area could feasibly support for the transfer of energy.

If the import capability is higher than the balancing authority area's flexible ramping product up requirement, then the balancing authority area's flexible ramping product is effectively 0 MW. That is none of the balancing authority area's upward flexible ramping product needs to be awarded to internal resources. Under typical conditions, all balancing authority areas generally have larger import or export

³ This was discussed at the February 2, 2018 Market Surveillance Committee meeting. The presentation is available at <http://www.caiso.com/Documents/Presentation-FlexibleRampingProductPerformanceDiscussionFeb22018.pdf>

limits than their flexible ramping up or flexible ramping down requirement. Within an interconnected system with multiple areas, a flexible ramping product can be counted towards other areas by wheeling through other balancing authority areas. However, only the transfer capability with adjacent balancing authority areas is considered when calculating the net import/export capability. This is true for all balancing authority areas in the EIM footprint.

Currently, the CAISO is the largest driver of the system-wide flexible ramping product requirement because it has the largest load and penetration of variable energy resources. The CAISO requirement for the flexible ramping product that must be procured from internal resources is effectively zero⁴ given the large import and export capability of the CAISO. But, since the CAISO has such a large share of the requirement, a portion needs to be procured within the balancing authority area in order to be available for uncertainty that materializes in the CAISO balancing authority area.

The CAISO proposes to enforce a minimum flexible ramping requirement in the CAISO balancing authority area, which will ensure that a minimum amount of the flexible ramping product will be procured from resources within the CAISO balancing authority area. The minimum amount will need to be higher than the historical procurement that resulted from the system-wide flexible ramping product constraint. Over time, based upon its evaluation of historical flexible ramping product procurement, the CAISO will refine the minimum CAISO requirement and the CAISO will update the CAISO minimum requirement through the business practice manual change process, which includes an opportunity for stakeholder input. The CAISO will also evaluate if similar minimum requirements are needed for other balancing authority areas. CAISO will perform the same historical evaluation and discuss its findings through the regularly held Market Performance and Planning Forum meetings. Any changes to such requirements will be proposed to stakeholders through the business practice manual change management process.

5. Deliverability Enhancement

Procurement of the flexible ramping product is based on opportunity costs, which arise from the trade-offs between the need for energy and the need for ramping capability. The market does not consider locational constraints when procuring the flexible ramping product. This results in under-utilization or under-deployment of the flexible ramping product.

The complication relates to congestion from internal constraints within a balancing authority area. The market enforces transmission constraints within each balancing authority area, which allows the market to economically manage congestion. As part of the congestion management process resources can move up if they help to mitigate the congestion, or down if they exacerbate congestion. Since flexible ramping product is not locational-based, this part of congestion management does not explicitly account for the flexible ramping product procurement. As a result, the market can procure upward flexible ramping capacity from resources that are dispatched down for congestion management, which in next

⁴ See figure 73 from the Price Performance Report available at <http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf>

market run if uncertainty materializes cannot be deployed because of the need to manage the congestion. This interplay between congestion and flexible ramping product procurement can be further complicated because the market may find it optimal to allocate upward flexible ramping product capacity precisely to resources dispatched down for congestion management. A similar dynamic exists for downward flexible ramping capacity and resources dispatched higher for energy to provide counter flow to mitigate congestion. However, the market has no mechanism to avoid this outcome.

As discussed in the *Day-Ahead Market Enhancements* initiative, similar deliverability concerns exist for the proposed imbalance reserve product. At this time, the CAISO believes that the approach to address deliverability of the real-time market flexible ramping product can inform the approach to ensure deliverability of the day-ahead imbalance reserve product. The remainder of this section discusses the pros and cons of zonal procurement versus nodal procurement.

5.1 Zonal procurement

Zonal procurement introduces sub-regions within balancing authority areas to distribute the flexible ramping product requirement more granularly in an effort to minimize stranded ramping capability. The zonal approach ensures that the flexible ramping product is not procured predominantly in one area, which would reduce the probability that ramping capability is not available. This is similar to how the CAISO currently procures ancillary services. Because the CAISO could leverage from its existing ancillary service functionality, this option would call for fewer software enhancements and computational requirements.

Similar to how flexible ramping product awards are limited by the EIM transfer capability between balancing authority areas, transmission capability between sub-regions will limit that amount of flexible ramping product awards than can be met by resources outside the sub-region. However, if the zones have internal congestion then the risk remains that flexible ramping product awards will not be deliverable. To the extent that there is persistent internal congestion, this may require that the zone be separated into more granular sub-regions. Again, this is similar to the process the CAISO goes through today to determine the appropriate ancillary services procurement regions.

Once sub-regions have been established, an approach to how the requirement is established for each sub-region is needed. Currently a requirement is calculated for each balancing authority area individually and for the whole EIM footprint. It may not be practical to perform the same calculation for each individual sub-region. Therefore, the distribution of the system requirement may not be based upon the actual uncertainty in a given sub-region, but by for example the net load ratio share by sub-region. This can lead to higher costs as minimum requirements could award the flexible ramping product to higher cost resources internally to a sub-region even though in this interval the transmission constraints between sub-regions were not binding. This may also lead to additional unit commitment within a zone to cover the worst case scenario within the zone. Lastly, rules will need to be developed to allow operators to block certain resources from being awarded the flexible ramping product. The CAISO operators currently can block certain resources from being awarded ancillary services if it is determined that the resources capacity will be unavailable due to congestion.

5.2 Nodal procurement

Nodal procurement ensures that both energy and flexible ramping awards are transmission feasible. This requires the introduction of deployment scenarios to ensure that energy plus upward flexible ramping product awards and energy less downward flexible ramping product awards are transmission feasible. This ensures that upward flexible ramping product awards are not given to resources located behind a transmission constraint and downward flexible ramping product awards are not given to resources providing counter flow to resolve a transmission constraint.

The nodal approach is a more durable solution to address operational concerns and more accurately price flexibility. As more solar, wind and other zero marginal energy cost resources make up a larger portion of the generation fleet, the marginal cost of energy will be lowered. The compensation of flexible generation will come more from flexible ramping product payments than energy payments.

However, the implementation complexity and computational requirements necessary to move to locational flexible ramping product are significant. In addition, because system conditions may change congestion patterns from the time the flexible ramping product was awarded, the nodal approach does not ensure 100% deliverability. The nodal approach only can ensure that the market does not award to resources that it knows at the time of the applicable market run would not be deliverable.

In looking forward to applying a nodal approach for the imbalance reserve product, the introduction of multiple deployment scenarios may necessitate the need for a congestion hedge for the ramping capability being held in addition to energy.

6. Stakeholder Engagement and Next Steps

Stakeholder input is critical for developing market design policy. The schedule proposed below allows several opportunities for stakeholder's involvement and feedback.

6.1 Schedule

Table 1 lists the planned schedule for the *Flexible Ramping Product Refinements* stakeholder process.

Table 1 : Proposed schedule for the FRP Refinements stakeholder process

Item	Date
Post Issue Paper/Straw Proposal	November 14, 2019
Stakeholder Conference Call	November 21, 2019
Stakeholder Comments Due	December 5, 2019
BPM Language within a Proposed Revision Request - PDR	ASAP

BPM Language within a Proposed Revision Request – Buffer & Minimum	Aligned with Fall 2020 release
Deliverability Enhancements	TBD

The ISO will discuss this issue paper/straw proposal during a stakeholder conference call on November 21, 2019. The ISO requests that stakeholders submit written comments by December 5, 2019 to InitiativeComments@caiso.com.

6.2 EIM Governing Body Role

The rules that govern decisional classification were amended in March 2019 when the Board adopted changes to the Charter for EIM Governance and the Guidance Document. An initiative proposing to change rules of the real-time market now falls within the primary authority of the EIM Governing Body either if the proposed new rule is EIM-specific in the sense that it applies uniquely or differently in the balancing authority areas of EIM Entities, as opposed to a generally applicable rule, or for proposed market rules that are generally applicable, if “an issue that is specific to the EIM balancing authority areas is the primary driver for the proposed change.”

This initiative does not satisfy the first test, because any proposed rules would be generally applicable to the entire ISO market footprint, rather than EIM-specific. Moreover, primary driver for pursuing these objectives is not an issue that is specific to the EIM balancing authority areas. The improvements to FRP deliverability will seek to minimize instances where ramping capability is stranded behind all kinds of transmission constraints. While EIM transfer limits are one type of constraint, they are only one of several types. Moreover, the CAISO identified the need for this initiative based on a study of pricing in the CAISO’s balancing authority area. Accordingly, this initiative would fall entirely within the advisory role of the EIM Governing Body.

Stakeholders are encouraged to submit a response to the EIM categorization in their written comments following the conference call for the Issue Paper/Straw Proposal, particularly if they have concerns or questions