PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 13, 2021

VIA ELECTRONIC FILING

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

Re: UE 390—PacifiCorp Surrebuttal Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Surrebuttal Testimony and Exhibits of the following witnesses.

- Douglas R. Staples (PAC/1000)
- Michael G. Wilding (PAC/1100)
- Dana M. Ralston (PAC/1200)
- Seth Schwartz (PAC/1300)
- Mary M. Wiencke (PAC/1400)
- Robert M. Meredith (PAC/1500)

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

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

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosures

CERTIFICATE OF SERVICE

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

Service List
UE 390

AWEC	
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
SBUA	
JAMES BIRKELUND SMALL BUSINESS UTILITY ADVOCATES 548 MARKET ST STE 11200 SAN FRANCISCO CA 94104 james@utilityadvocates.org	DIANE HENKELS **(C)** SMALL BUSINESS UTILITY ADVOCATES 621 SW MORRISON ST. STE 1025 PORTLAND OR 97205 diane@utilityadvocates.org
DARREN WERTZ **(C)** SMALL BUSINESS UTILITY ADVOCATES wertzds@gmail.com	
SIERRA CLUB	
ANA BOYD **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 ana.boyd@sierraclub.org	THIEN CHAU **(C)** **(HC)** SIERRA CLUB thien.chau@sierraclub.org
ROSE MONAHAN **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org	
STAFF	
SCOTT GIBBENS **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON 201 HIGH ST SE SALEM OR 97301 scott.gibbens@state.or.us	SOMMER MOSER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us
MOYA ENRIGHT **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 moya.enright@state.or.us	

Dated this 13th day of August, 2021.

Mary Penfield
Adviser, Regulatory Operations

REDACTED
Docket No. UE 390
Exhibit PAC/1000
Witness: Douglas R. Staples

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Douglas R. Staples

August 2021

TABLE OF CONTENTS

Q. Are you the same Douglas R. Staples who adopted the initial testimony of David G. Webb and submitted reply testimony in this proceeding on behalf of PacifiCorp dba Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of the Public Utility Commission of Oregon (Commission) Staff (Staff) witnesses Ms. Moya Enright, Ms. Kathy Zarate, Dr. Curtis Dlouhy, Mr. Scott Gibbens, Ms. Rose Anderson, and Mr. John Fox; Alliance of Western Energy Consumers (AWEC) witness Mr. Bradley G. Mullins; Oregon Citizens' Utility Board (CUB) witness Mr. Bob Jenks; and Sierra Club witness Mr. Ed Burgess as it relates to the Company's modeling of net power costs (NPC) for the 2022 Transition Adjustment Mechanism (TAM).

Q. Please summarize your surrebuttal testimony.

A. I demonstrate the reasonableness of PacifiCorp's approach to forecasting NPC in the 2022 TAM through the following points:

- The modeling of the CSAs at Dave Johnston, Craig, Hunter, and Huntington should be found prudent.
- PacifiCorp's Market Cap Methodology as proposed is a simple and straightforward modeling adjustment that more accurately reflects the market depth that is available to the Company for market sales. The adjustments to this proposal filed by parties would decrease the accuracy of NPC.

- PacifiCorp recommends that the Commission reject Staff's and Sierra Club's proposed changes to the "informational run" as such changes would assume away costs that are incurred in actual operations. These assumptions would essentially render the study meaningless.
- The Company will remove the proposal to change the EIM allocation factor from this proceeding and plans to address this issue in PacifiCorp's next round of Multi-State Protocol (MSP) negotiations
- With regards to the other adjustments proposed by the parties, PacifiCorp recommends the Commission reject: (1) Staff adjustments regarding qualifying facility (QF) forecasting, and (2) AWEC's adjustment on other revenues.

Q. Please identify the other witnesses providing surrebuttal testimony supporting the 2022 TAM.

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

- Mr. Michael G. Wilding, Vice President, Energy Supply Management, responds to Staff's adjustment on the Nodal Pricing Model.
- Mr. Dana M. Ralston, Senior Vice President of Thermal Generation and Mining, testifies in support of the prudence of the Company's CSAs and responds to Sierra Club's concerns on costs at Bridger Coal Company (BCC).
- Mr. Seth Schwartz, President, Energy Ventures Analysis, Inc., responds to the concerns raised by Sierra Club.
- Ms. Mary M. Wiencke, Vice President, Transmission Regulation and Market Policy, provides testimony to address the transfer of Renewable Energy Credits.

- Mr. Robert M. Meredith, Director, Pricing and Cost of Service, responds to the concerns raised by the Small Business Utility Advocates and addresses the calculation of the Consumer Opt-Out Charge in response to the testimony of Calpine Energy Solutions, LLC (Calpine).

Q. Has PacifiCorp changed its net power cost (NPC) recommendation in its surrebuttal testimony?

A. No.

II. FORECASTING COAL GENERATION

A. <u>Response to Staff 's and CUB's Recommendations on Coal Unit Forecasting, Economic Cycling, and Prudence of CSAs.</u>

Q. Please provide a general overview of Staff's recommendations to which you are responding in this section.

A. Staff has accepted the Company's responses regarding the burn rate at Naughton,[1] the minimum take modeling for Wyodak,[2] and the prudence of the Huntington CSA. But Staff has expanded its recommendations on other issues. Staff still asserts that PacifiCorp's recent CSAs for the Dave Johnston and Craig plants should be deemed imprudent because the Company did not model economic cycling during CSA negotiations, and Staff has now reversed its original position and added the Hunter CSA to that adjustment.[3] As a remedy, Staff proposes that the minimum take levels in these three CSAs be disregarded in the TAM. While this would not result in any adjustment in this case (because all plants are being dispatched above their

[1] Staff/1500, Fox/6.
[2] Staff/1500, Fox/7.
[3] Staff/1400, Anderson/4.

minimums), it could produce a significant disallowance in the future if, for any reason, plant dispatch is reduced.

Staff also now recommends that the Commission provide guidance to PacifiCorp for future prudence reviews of CSAs.[4] Specifically, for the first time, Staff recommends that the Company (1) "should provide an in-depth explanation of how the Company considered the potential for economic cycling" when negotiating minimum take levels, (2) must supply evidence that it "reached out to co-owners to request they consider [economic] cycling," (3) must provide a chart "comparing the MMBtus from the generation forecast used to inform contract negotiations to the number of MMBtus that PacifiCorp will be contractually obligated to pay for at each plant," and (4) "should provide workpapers for the generation forecasts used to inform negotiations on each new coal contract introduced" in each future TAM filing.[5]

Staff also adopts Sierra Club's recommendation to require the Company to provide copies of its highly confidential CSAs and affiliate mine plans in future TAM filings, and CUB's proposal requiring the Company to conduct an additional study that closes Jim Bridger Unit 1 for the entirety of quarter two or, alternatively, "identify economic cycling opportunities across PacifiCorp's system" in a new Economic Cycling Study.[6] Finally, Staff still asserts that the modeling of the Informational Run should exclude liquidated damages and "take or pay" provisions.[7]

[4] Staff/1400, Anderson/7-8.
[5] Staff/1400, Anderson/5-6.
[6] Staff/1400, Anderson/17-18.
[7] Staff/1500, Fox/5.

Q. Please provide a general response to Staff's testimony on forecasting coal generation.

A. Without analytical support, Staff posits that economic cycling will significantly reduce coal burns and minimum take requirements across PacifiCorp's system and reduce costs to customers. Staff largely ignores PacifiCorp's evidence that economic cycling has, at most, *de minimis* economic benefit for PacifiCorp's customers.[8] In recommending that the Commission find the CSAs at Dave Johnston, Craig, and Hunter imprudent, Staff discounts the actual modeling PacifiCorp conducted, creates and retroactively applies an entirely new prudence standard contrary to current Commission precedent, and ignores the fact that the Generation and Regulation Initiative Decision Tool (GRID) model dispatches each of these plants well above their contractual minimums in studies that include economic cycling, confirming that the forecasted generation volumes are reasonably required to serve load.

1. History of Economic Cycling and Minimum Take Provisions in PacifiCorp's TAMs

Q. Has the Commission ever ordered PacifiCorp to model economic cycling of its coal plants to support execution of a CSA or demonstrate the reasonableness of its proposed NPC?

A. No. To the contrary, this issue was fully litigated in the 2018 TAM, docket UE 323, and the Commission rejected Staff's recommendation to require PacifiCorp to model economic cycling for its coal units.[9]

[8] PAC/100, Web/17.
[9] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 10 (Nov. 1, 2017) [hereinafter 2018 TAM].

Q. Has the Commission ever concluded that a CSA was imprudent because it included a minimum take provision?

A. No. This issue was also recently litigated in the 2017 TAM, docket UE 307, and the Commission rejected CUB's prudence challenge to the minimum take provisions in the CSAs for the Jim Bridger, Huntington and Dave Johnston plants.[10]

Q, Has the Commission ever prohibited PacifiCorp from modeling the impact of a minimum take provision in a CSA as Staff proposes in this case?

A. No. This issue was also fully litigated in the 2017 TAM, and the Commission rejected Staff's challenge to the Company's iterative approach to ensure minimum take volumes are properly captured in GRID.[11]

Q. On what basis did the Commission reject Staff's recommendation to require the modeling of economic cycling at PacifiCorp's coal-fired facilities in the 2018 TAM?

A. The Commission agreed with PacifiCorp that the GRID model "reflects historic, normalized practices regarding economic shutdowns of coal units."[12] However, the Commission also recognized that "PacifiCorp's actual operations may be changing under evolving market conditions" and directed the Company to discuss economic cycling at a coal workshop.[13]

---

[10] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 9 (Dec. 20, 2016) [hereinafter 2017 TAM].
[11] 2017 TAM, Order No. 16-482 at 11.
[12] 2018 TAM, Order No. 17-444 at 11.
[13] *Id.*

Q. Have PacifiCorp's actual operations changed since the 2018 TAM with respect to economic cycling?

A. No. The Company economically cycled a limited number of coal plants in 2016 and 2017 due to historical anomalies in natural gas pricing and hydro generation. Since this time, the Company has not economically cycled coal plants at any significant level because of higher natural gas prices, lower hydro generation, and lower minimum operating levels at coal-fired facilities. In addition to those considerations, the continued addition of renewable resources into the Company's generation fleet requires the presence of significant online dispatchable resource capacity to integrate and reliably serve load with those new resources.

Q. Did the removal of the "must run" settings in GRID in this case far overstate the Company's actual economic cycling in light of these constraints?

A. Yes. For example, by removing must run settings in the 2021 TAM, GRID forecast [redacted] total avoided run hours through July, of which approximately [redacted] hours were not dictated by forced, planned, or maintenance outages. In actuality, through July of 2021, when coal plants have been historically allowed to conduct limited cycling, the Company had only [redacted] hours of offline time ([redacted] percent of forecast) that was not attributable to forced, planned, or maintenance outages. To be clear, 2021 has been fairly unusual due to abnormally low hydro conditions, but it is difficult to imagine that this year would have played out the way GRID projected it to, even if it had been closer to normal.

Q. Has the Company been pursuing a strategy that allows it to reduce coal generation more effectively and reliably than through economic cycling?

A. Yes. This is evident in the Company's initial filing in this case, which demonstrated a $114 million reduction in coal costs as compared to the 2021 TAM due to lower coal generation. Of this amount, only $[redacted] is attributable to the removal of the must run setting and economic cycling. In actual operations, the Company has achieved this significant reduction in coal generation largely by a combination of adding new renewable generation and reducing minimum stable run levels at PacifiCorp's coal generation facilities.[14] As described in Mr. Daniel J. MacNeil's reply testimony, the inclusion of these renewable resources requires the online displacement of coal generators to support and integrate ever-increasing amounts of non-dispatchable generation. Coal generators have the greatest ability to reduce output during low-price periods owing to the reduction in minimum stable run levels pursued by the Company over the past several years.[15] This approach is better calibrated to reduce coal generation but makes cycling in actual operations more difficult to achieve.

Q. Can you provide an example that demonstrates the efficacy of the Company's strategy as compared to economic cycling for reducing coal generation?

A. Yes. In the 2022 TAM modeling, the impact of removing Energy Vision 2020 resources from the system was an [redacted] in coal generation of approximately [redacted] megawatt-hours (MWh) (about [redacted] percent),[16] while reinstating the must run condition only [redacted] coal generation by approximately [redacted] MWh

---

[14] A chart showing how these minimums have reduced over time was provided in my reply testimony. PAC/400, Staples/60.
[15] PAC/700, MacNeil/4
[16] PAC/100, Webb/28.

(about [redacted] percent).[17] In addition to being more impactful and more supportive of system reliability, the Company's approach can be enacted in actual operations. On the other hand, coal cycling is difficult to achieve in actual operations because of reliability concerns.

Q. Has the Company incorporated limited economic cycling into its coal forecast modeling as part of a non-precedential settlement?

A. Yes. In the 2019 TAM, docket UE 339, PacifiCorp entered into a partial stipulation with Staff, AWEC, CUB, and Calpine Solutions[18] to model economic cycling for (1) majority-owned units, (2) that do not participate in the Energy Imbalance Market (EIM), and (3) are not under operational constraints precluding economic shutdowns.[19] The stipulation limited the cycling period from February 1 to May 31 and operated by removing the must run setting for the limited facilities.[20]

Q. What were the results of this limited modeling of economic cycling?

A. Even the limited economic cycling allowed in GRID during the 2019 and 2020 TAMs allowed for more economic cycling than realized in actual operations due to the model's perfect foresight and the Company's implementation of low minimum operating levels for its coal-fired facilities. Specifically, the Company showed that in the 2019 TAM, GRID forecast [redacted] hours of offline time and approximately [redacted] avoided MWh. But in actual operations, PacifiCorp only achieved [redacted] hours of offline time and approximately [redacted] avoided MWh.[21]

---

[17] PAC/100, Webb/17.
[18] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, App'x A at 6 (Oct. 26, 2018) [hereinafter 2019 TAM].
[19] 2019 TAM, PAC/100, Wilding/35.
[20] 2019 TAM, PAC/100, Wilding/35.
[21] Docket No. UE 375, PAC/500, Webb/19-20.

Q. Did PacifiCorp later agree to expand economic cycling for coal forecast modeling in a second nonprecedential settlement related to the transition to Aurora?

A. Yes. In a partial stipulation in the 2021 TAM, docket UE 375, the Company agreed to remove all must run settings as a part of the transition to Aurora and to hold quarterly calls in 2021 to provide information on the dispatch of its coal facilities and market conditions.[22]

2. Response to Staff's Recommendations Regarding Economic Cycling

Q. Staff recommends that PacifiCorp's CSAs should be deemed imprudent unless the Company models economic cycling according to Staff's new proposed standards prior to contract execution.[23] Would modeling economic cycling as Staff proposes appreciably reduce generation to below minimum take commitment levels?

A. No. While I am not an expert on CSA negotiations, the modeling of economic cycling in GRID over the past four years has shown that economic cycling has a minimal impact on coal generation forecasts. Even taking GRID's inflated numbers for predicted economic cycling in this and previous TAMs, the generation [redacted] from economic cycling has only resulted in a small percent [redacted] in coal burn (less than [redacted] percent in the initial filing in this case).

---

[22] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, App'x A at 6, 8 (Oct. 30, 2020) [hereinafter 2021 TAM].
[23] Staff/1400, Anderson/4.

Q. Staff recommends a prudence disallowance for the Company's Dave Johnston CSAs because "PacifiCorp must evaluate economic cycling at its coal plants."[24] Does Staff cite any precedent supporting such a disallowance?

A. No, nor does Staff reconcile the directly relevant Commission precedent outlined above. Staff's assertion that "a full assessment of economic cycling on PacifiCorp's system as a whole is needed before PacifiCorp signs its coal supply agreements" is contrary to previous TAM orders.[25] While PacifiCorp voluntarily agreed to explore economic cycling for calculating its NPC in two stipulations as part of the give and take of settlement negotiations, the Commission has never stated nor implied that this is now a prerequisite to execution of a prudent CSA—especially when it remains out of sync with PacifiCorp's actual approach to optimizing its system.

Q. Does the Commission's prudence standard support Staff imposing its newly announced CSA standards to CSAs executed last year?

A. No. Staff's *ex post facto* position that the Company should have modeled economic cycling according to the new CSA standards Staff announced in its rebuttal testimony violates the Commission's prudence standard. As I understand it, this standard requires review of the facts and circumstances at the time of the execution of the CSAs, prohibits hindsight review and retroactive application of new standards, and requires only that the Company acted in an objectively reasonable manner.[26]

---

[24] Staff/1400, Anderson/10.
[25] Staff/1400, Anderson/10.
[26] 2017 TAM, Order No. 16-482 at 6 (In a prudence review, [the Commission] look[s] at the objective reasonableness of a decision at the time it was made, considering the information then available to the utility.").

Q. Regardless, did the Company allow economic cycling of Dave Johnston for its model runs informing CSA negotiations?

A. Yes. After filing its reply testimony, the Company continued to review the modeling that supported execution of the Dave Johnston CSAs. The Company determined that this modeling did in fact allow Dave Johnston to economically cycle.

Q. Does Staff concede that the Dave Johnston plant is unlikely to cycle because of the plant's low dispatch cost?[27]

A. Yes. While Staff recognizes that Dave Johnston "is unlikely to be elected for economic cycling because of its relatively low cost," it still contends that the CSAs should be deemed imprudent based on standards the Commission has never previously adopted.[28] As detailed more thoroughly in Mr. Ralston and Mr. Schwartz's testimony, the Commission should reject Staff's recommendation.

Q. Staff also suggests that the Craig CSA should be disallowed even though the minimum take levels for Craig "[redacted]"[29] How do you respond?

A. This recommendation also appears contrary to the Commission's prudence standard of objective reasonableness. Modeling economic cycling for Craig would not have changed the minimum take provisions in the Craig CSA, which are already low and relatively flexible. Furthermore, as explained in the testimony of Mr. Ralston, Craig would likely never economically cycle in actual operations because the plant is jointly

[27] Staff/1400, Anderson/10.
[28] Staff/1400, Anderson/11.
[29] Staff/1400, Anderson/10 (Staff has marked this statement as highly confidential, PacifiCorp would redesignate this statement confidential).

owned.[30] While Staff finds this response "unconvincing," it has provided no evidence to counter this operational reality that could never be captured in the GRID model.[31] A follow-up analysis of cycling at Craig using the business plan base study as a starting point indicates that projected generation was approximately [redacted] percent [redacted] with cycling enabled, further demonstrating that cycling does not materially alter projected generation at the Company's coal facilities. Allowing cycling at Craig would still have supported the volumetric requirements of the CSA.

Q. Does Staff continue to view the Hunter modeling as "robust and appropriate," as Staff testified in its rebuttal testimony?[32]

A. No. Staff has changed its position and now contends that the Hunter CSA is imprudent because the Company did not "assess whether economic cycling at any of its coal plants can reduce costs for ratepayers while maintaining reliability and other system requirements."[33] As described in the reply testimony of Mr. MacNeil, PacifiCorp modeled the economic cycling of Hunter before executing the CSA as a part of its analysis.[34] Staff now claims that PacifiCorp's analysis was insufficient—even though Staff previously praised this analysis. Mr. Ralston addresses Staff's retroactive approach to modeling economic cycling in his surrebuttal testimony. Suffice it to say, Staff's shifting position on the prudence of the Hunter CSA demonstrates that Staff's prudence standard is new and novel, and not one that PacifiCorp could have reasonably been aware of at the time it executed the CSA.

---

[30] PAC/600, Ralston/15-16.
[31] Staff/1400, Anderson/10.
[32] Staff/700, Anderson/18.
[33] Staff/1400, Anderson/11.
[34] PAC/700, MacNeil/3-4 ("Hunter Units 1 and 2 were allowed to cycle in the spring, consistent with assumptions previously used in Oregon TAM Filings.")

Q. Did Staff address the limited cycling that PacifiCorp allowed during the Hunter CSA modeling?

A. No. Staff seems to suggest that all coal units must be allowed to cycle, year-around, in any modeling for a prudent CSA, irrespective of the Company's actual operations and reliability concerns. As explained in the reply testimony of Mr. MacNeil, the Company employed a reasonable amount of economic cycling in its GRID analysis to support the Hunter CSA.[35]

Q. Staff also believes that "without studying the economic cycling outcome for each of its coal plants, PacifiCorp's estimate of the optimal level of generation at any of its dispatchable plants will be inaccurate, and therefore the Company cannot optimally set its minimum take levels in any of its coal contracts."[36] Do you agree with this reasoning?

A. No. First of all, as described in the testimony of Mr. Ralston, the Company does not unilaterally set the minimum take levels in any of its coal contracts. Rather, the minimum take levels are negotiated with coal suppliers along with other key contract terms. Further, as detailed above, modeling economic cycling during CSA negotiations would have a *de minimis* effect on the coal generation forecast and minimum take levels. As the Company has explained in this proceeding and consistently over the past five years, the Company's increased renewable generation, reduced minimum operating levels, and reduced hydro generation have made economic cycling much less likely across PacifiCorp's system.

[35] PAC/700, MacNeil/4-5.
[36] Staff/1400, Anderson/10.

The Commission's prudence standard "does not require perfection; just that the utility's actions were reasonable."[37] Modeling a reasonable level of economic cycling for the Dave Johnston and Hunter CSAs and forgoing this modeling for the Craig CSA was reasonable considering the lack of historical cycling across these three facilities, the low dispatch cost of Dave Johnston, and the joint ownership of Craig.

In addition, enabling a unit to cycle in isolation should produce a similar or slightly lower projected burn when compared to a study with all units permitted to cycle. The reason is that, when searching for displaceable units, a model with all units enabled for cycling may choose to displace a higher cost resource instead of the unit in question, but if only one unit can be cycled, it will be removed from service whenever it is not needed to support sales or serve load. Staff's concern that "the minimum take commitment level is kept as low as reasonably possible"[38] is misguided. The appropriate concern is whether the CSAs support safe and reliable service to customers in a least cost, least risk manner. Mr. Ralston further expands on this concept and explains how these CSAs meet this standard.

Q. Were the units in question permitted to cycle in the studies submitted in the 2022 TAM?

A. Yes. All of them cleared the minimum take commitment tiers without any adjustment required to the incremental cost, which is a further illustration of the reasonableness of the Company's modeling approach.

[37] 2017 TAM, Order No. 16-482 at 6.
[38] Staff/1400, Anderson/4.

Q. Finally, Staff continues to advocate for a follow-up economic cycling study that "seeks to identify additional opportunities of cost savings through economic cycling."[39] Does the Company agree to this proposal?

A. Consistent with the 2021 TAM settlement, a party may request a modeling run from the Company. However, it is important to note that the TAM, as a ratemaking mechanism does not drive actual operations; instead, the TAM is designed to forecast the Company's actual NPC as accurately as possible. As described above in my testimony, the TAM is already forecasting far more economic cycling than actually occurs in operations.

3. Jim Bridger Cycling Study

Q. CUB continues to assert that conducting a study on the economic cycling of Jim Bridger Unit 1 would provide more information about "the economic viability of the Company's simulated dispatch in the GRID forecast."[40] Is the Company willing to model the Jim Bridger Unit 1 economic cycling?

A. Consistent with the 2021 TAM settlement, CUB can request these assumptions in a modeling run with Aurora in the 2023 TAM. However, for the reasons stated in my reply testimony, this information may be of limited value.

[39] Staff/1400, Anderson/8.
[40] CUB/200, Jenks/12.

Q. CUB continues to argue that the Integrated Resource Plan (IRP) action plan "raised questions as to whether customers are better off with Jim Bridger Unit 1 operating in 2022 and 2023."[41] Does the IRP action plan impact NPC as forecast in the GRID model?

A. No. As CUB recognizes, the NPC GRID model is a one-year simulation of dispatched resources under normalized conditions.[42] Any long-term economic benefit the stochastic IRP model found in cycling or shutting down Jim Bridger Unit 1 does not affect how GRID models the operation of Jim Bridger Unit 1 in the 2022 TAM.

Q. CUB seems to suggest that conducting its proposed Jim Bridger Unit 1 study now "would provide additional information about the economical operation of the plant and might inform how we develop transition plans" for other coal facilities.[43] Please respond.

A. It is not clear how a modeling run that prohibits Jim Bridger Unit 1 from running would help in the development of transition plans, and it seems this may be a more appropriate issue for the IRP.

---

[41] CUB/200, Jenks/14.
[42] CUB/200, Jenks/15.
[43] CUB/200, Jenks/15.

4. Response to Staff's Other Recommendations

Q. Staff agrees with Sierra Club that PacifiCorp should provide copies of its highly confidential CSAs and affiliate mine plans in each TAM filing.[44] Is there a separate process for reviewing these documents?

A. Yes. While Mr. Ralston's surrebuttal testimony will elaborate on this issue, it is my understanding that these documents are already made available to parties in the TAM if requested under the TAM's modified protective order.

Q. Staff also continues to believe that the Informational Run should be exclusive of all costs associated with liquidated damages provisions or take or pay contracts.[45] Do you agree with this assessment?

A. No. I continue to believe that removing these costs that would be incurred would make the informational run meaningless because these costs cannot be avoided by the Company in actual operations.

Q. Staff believes that removing these costs would still allow the Informational Run to "provide insight into opportunities for cost savings in the future."[46] How do you respond?

A. An informational model that does not account for costs the Company would incur cannot provide insight into cost savings. In other words, any savings found in the Informational Run must be compared against the costs incurred while generating those potential savings. Eliminating costs that would be incurred if this course of

[44] Staff/1400, Anderson/6-7.
[45] Staff/1500, Fox/4-5.
[46] Staff/1500, Fox/3.

action were pursued in actual operations exaggerates any potential savings and provides no meaningful feedback to the Company or to stakeholders.

B. Response to Sierra Club's Recommendations on Coal Forecasting and Economic Cycling

1. Sierra Club's Proposed NPC Adjustment

Q. Based on Sierra Club's assertion of "inappropriate" fuel costs for Jim Bridger, does it propose an adjustment to the Company's 2022 NPC forecast?

A. Yes. Sierra Club proposes that the Commission reduce the 2022 NPC forecast by $[redacted] total company or $[redacted] Oregon-allocated.[47]

Q. Why does Sierra Club believe that such a reduction is appropriate?

A. Sierra Club bases its adjustment on the Company's GRID run that substituted average cost for marginal costs at Jim Bridger without making any further adjustments.[48]

Q. Does this model run provide an accurate estimate of NPC for 2022?

A. No. The Company provided this model run for informational purposes in response to Sierra Club's Data Request 2.22 and not as a replacement for the Company's actual 2022 TAM, which uses the marginal fuel cost for modeling all of PacifiCorp's generation resources.

Q. Sierra Club asserts that even with this adjustment the Company will be able to recover fixed costs at BCC.[49] Do you agree?

A. No. As explained in great detail in Mr. Ralston's surrebuttal testimony, Sierra Club consistently misrepresents the level of fixed costs at BCC.

---

[47] Sierra Club/200, Burgess/20.
[48] Sierra Club/200, Burgess/21; Sierra Club/123 (Sierra Club Data Request 2.22 Model Run).
[49] Sierra Club/200, Burgess/22.

Q. Sierra Club argues that its average cost model run's coal fuel expenditures of [redacted] for Jim Bridger will be "more than sufficient" to cover remaining costs of "scaled down BCC production and other obligations" at the plant.[50] Do you agree?

A. No. The Company's actual 2022 GRID run from the update filing projects Jim Bridger fuel costs totaling $180.6 million, creating a deficit of $[redacted] from projected NPC. In addition, as Mr. Ralston explains, Sierra Club's estimates of the scalability of BCC costs is incorrect, owing to their refusal to acknowledge the level of fixed costs that accompany mining operations.

Q. Sierra Club purports to show that "sunk costs" at Jim Bridger are "substantially lower" than its average cost model run.[51] Is this accurate?

A. No. This assumption is based on incomplete data and a misrepresentation of the Company's response to Sierra Club's Data Request 5.5(b). In this data request, the Company explained that it has already spent $[redacted] *as of April 1, 2021*, attributable to 2022 BCC production but that this cost does not account for all cost obligations the Company has for 2022 BCC coal production. Mr. Ralston addresses this issue in more detail in his surrebuttal testimony.

Q. Sierra Club's assumptions in its average cost run also require a [redacted] reduction in BCC production for 2022.[52] Is this possible considering operational constraints and reliability concerns?

A. No. As explained more thoroughly in the testimony of Mr. Schwartz and Mr. Ralston,

[50] Sierra Club/200, Burgess/23.
[51] Sierra Club/200, Burgess/23.
[52] Sierra Club/200, Burgess/24 n.39.

BCC cannot operate at a [redacted] reduced capacity and still produce coal at the same dispatch price assumed in the GRID model run because of reduced economies of scale and inefficient use of mine equipment and workforce constraints.

Q. Sierra Club believes that the Company did not address its argument that a "large portion" of fixed costs would still be recovered if PacifiCorp used average cost rather than incremental costs to model BCC costs without any post-modeling adjustments.[53] Did the Company ignore this argument?

A. No. The Company explained that it "does not use an average price as a dispatch price in short-term forecasts such as the TAM because the cost of coal in a take-or-pay volume tier is not avoidable."[54] Sierra Club's argument is also disingenuous and contrary to the purpose of the TAM. The TAM must be an accurate assessment of NPC for the forthcoming year. Sierra Club's unquantified and nebulous assertion that the Company would recover a "large portion" of its BCC costs through average costs ignores the Company's data and the fundamental ratemaking principle that PacifiCorp should have an opportunity to recover *all* of its reasonable and prudent costs. Furthermore, the re-averaging step in the Company's average cost model is essential to create an accurate NPC forecast. Rather than ignore Sierra Club's argument, the Company responded to it through a data request[55] and in my reply testimony.[56]

[53] Sierra Club/200, Burgess/5.
[54] PAC/400, Staples/52-53.
[55] Sierra Club/103, Burgess/9.
[56] PAC/400, Staples/66-67.

Q. In responding to your assertion that using average costs, instead of incremental costs, is contrary to basic economic principles, Sierra Club states that a seller's optimal price is marginal cost "only if the marginal cost is above the average cost."[57] Is this accurate?

A. No, this is simply wrong. First, a marginal cost above the average cost would indicate negative fixed costs, unless Mr. Burgess is trying to reference the diminishing marginal productivity that firms experience on the extremes of their range of production capabilities. Second, even if Mr. Burgess is attempting to make a point about marginal productivity, it is somewhat irrelevant as the marginal cost is the only factor worthy of consideration in either case. For example, if a firm can produce an item at an incremental cost of $20 and sell it for $25, it should produce and sell that item. The production and sale of that item will either defray costs or increase profits by $5. The firm's average cost has no bearing whatsoever on the decision. Consider the following example:

Figure 1

	Without Incremental Generation	With Incremental Generation
Fixed Costs	$800	$800
Variable Costs	$1,000	$1,010
Average Costs	$18	$17.92
Incremental Revenue	$0	$13
Output (MW)	100	101
Total Net Costs	$1,800	$1,797

In this scenario, the marginal cost of production is $10, which is well below the average cost of $18 per MWh—a cost scenario that Mr. Burgess believes should

[57] Sierra Club/200, Burgess/13 (emphasis omitted).

invalidate the marginal cost as an input to the decision. So long as the incremental revenue exceeds the incremental cost (in this case, incremental revenue was set to $13 in order to satisfy that condition), the decision to increase production will lower net costs.

The same is true when the incremental cost is above average cost. Consider the following example, which makes this point abundantly clear.

Figure 2

	Without Incremental Generation	With Incremental Generation
Fixed Costs	$800	$800
Variable Costs	$1,900	$1,950
Average Costs	$27	$27.23
Incremental Revenue	-	$51
Output (MW)	100	101
Total Net Costs	$2,700	$2,699

In this scenario, the marginal cost is set to $50/MWh, but the incremental revenue is $51/MWh to demonstrate that increasing production is still economically sound and cost minimizing so long as incremental revenue exceeds incremental costs, regardless of whether the incremental cost is above or below the average cost.

Q. Sierra Club also argues that marginal prices assumed in GRID are not reflective of true marginal prices because they are set to meet minimum takes.[58] How do you respond?

A. Sierra Club correctly notes that the Company uses an iterative approach to settle on an incremental pricing tier that satisfies minimum take obligations for *some* plants. This is primarily a consequence of the fact that GRID is not configured to accept

[58] Sierra Club/200, Burgess/13.

more than one dispatch price, and cannot recognize volumetric constraints, so the Company must find a way to align consumption with the cost structure. However, Sierra Club makes this observation when speaking specifically about the BCC supplemental pricing tier, which is used as the incremental cost for the Jim Bridger plant in GRID. In this TAM, the Jim Bridger incremental price required no adjustment at any point, as the BCC supplemental price easily satisfies the volumetric requirements of both the base supply contract and the base mine plan.

Q. Is PacifiCorp's supplemental pricing at BCC above the average cost?

A. No. The supplemental tier of pricing reflects the cost of incremental production, which is lower than average costs because of the existence of fixed costs at the mine. This is common in industries with high barriers to entry, of which the utility and mining industries are undoubtedly a part. However, as noted above, the relationship between average and incremental costs is irrelevant when making short-run economic decisions, which are the only sort of decisions contemplated in the TAM, as it is a one-year study to determine NPC based on existing obligations, constraints, contracts, and resources.

Q. Do you agree with Sierra Club's continued insistence that "it is generally favorable for the model to select an alternative resource that can displace coal from BCC, even if the alternative is more expensive on a per unit basis that the BCC supplemental coal supply"?[59]

A. No. Sierra Club's argument generally revolves around the supposition that fixed costs are not, in fact, fixed. This is why Sierra Club's analysis largely relies on a

[59] Sierra Club/200, Burgess/18.

study that was provided by the Company in discovery with a caveat that the "absence of a re-averaging step that is inclusive of all cost components invalidates this study as a means by which to determine the impact of the proposed change on net power costs (NPC)."[60] The scenario Sierra Club requested essentially denies GRID important information, first by failing to provide an accurate incremental price, then by withholding the impact of fixed costs, which cannot be accounted for separately in GRID and must be accounted for in the cost averaging step.

Q. Sierra Club argues that its analysis in Confidential Table 2[61] proves its point. Do you agree?

A. No. As explained in Mr. Ralston's testimony, Sierra Club's Confidential Table 2 is another example of Mr. Burgess mischaracterizing fixed costs as variable costs. Mr. Ralston's testimony demonstrates that when fixed costs are incorporated into the cost forecast, the course of action recommended by Sierra Club results in increased costs.

2. Operational Dispatch Practices

Q. Sierra Club continues to claim that the "extreme difference" between the BCC supplemental price and the BCC base price results in an over forecast of Jim Bridger generation in iOpt and Power Costs Incorporated (PCI).[62] Do you agree with this assessment?

A. No. Sierra Club agrees that "modest differences" between forecast and actual dispatch in energy trader forecasts are "expected and reasonable."[63] However, Sierra

[60] Sierra Club/103, PacifiCorp Response to Sierra Club Data Request 2.22.
[61] Sierra Club/200, Burgess/19.
[62] Sierra Club/200, Burgess/31.
[63] Sierra Club/200, Burgess/31.

Club suggests that the problem here is a matter of degree based on the supplemental price of BCC coal. But Sierra Club failed to acknowledge the unique position of Jim Bridger and its ability to provide reliable power to maintain system integrity throughout PacifiCorp's system. Essentially, Sierra Club repackages its core argument that PacifiCorp should model Jim Bridger using average cost (which Mr. Burgess attempts to rebrand as "long-run marginal cost" in his direct testimony)[64] rather than incremental costs, which is contrary to actual operations and economic principles as stated above.

Q. Sierra Club continues to advocate for an accounting of energy trader fuel cost assumptions in the PCAM as part of this proceeding, arguing that "it does not make sense to construct artificial procedural barriers to gathering relevant information on PacifiCorp's dispatch practices."[65] Please respond.

A. The TAM is meant to be a limited assessment of NPC for the next year and costs associated with customer transition to direct access. The limited nature of this proceeding is essential given the compressed timeline of the docket and the fact that it must be completed to ensure accurate power costs for the following year. Increasing the number of issues in this docket without asking for changes to the TAM Guidelines in a general rate case frustrates the purpose of the TAM as an expedited, limited docket.

---

[64] Sierra Club/100, Burgess/29
[65] Sierra Club/200, Burgess/32.

Q. Sierra Club also cites a 2019 Portland Business Journal article to argue that the Company's integration into an "organized regional energy market" could "exacerbate" the alleged inaccurate dispatch practices.[66] Do you agree with this assessment?

A. No. First, the dispatch practices to which Sierra Club objects are perfectly in keeping with basic economic principles. Second, the "organized regional energy market" in question is the EIM, which PacifiCorp already participates in. The only change being contemplated is the formation of an extended day-ahead market. There is no reason to believe that this will require a modified dispatch approach by the Company.

3. Economic Cycling

Q. You provided a hypothetical example of economic cycling in your reply testimony to illustrate how rarely economic cycling would occur for Jim Bridger due to startup costs.[67] Did Sierra Club find this example plausible?

A. Yes, although Sierra Club disagreed that it was representative of all possible system conditions Jim Bridger would face in a given year.

Q. Did Sierra Club provide any additional analysis to support its contention?

A. Yes. Sierra Club extended its previous analysis of a five-day period to cover iOpt/PCI forecasts from January 2020 through May 2021. Sierra Club concluded that this analysis shows many instances where economic losses were greater than the startup costs of any individual units. It provided this data in Confidential Table 4.[68]

[66] Sierra Club/200, Burgess/32.
[67] PAC/400, Staples/58-59.
[68] Sierra Club/200, Burgess/34.

Q. Have you reviewed Sierra Club's analysis?

A. Yes.

Q. Is Sierra Club's testimony deceptive by not discussing critical alterations that they made to the data that was provided by the Company?

A. Yes. Sierra Club's testimony makes two critical alterations to data that was provided by the Company.

First, in his "analysis," the actual fuel consumption as calculated by iOpt was replaced with Mr. Burgess' estimation, derived using static heat rates that do not account for the varying levels of efficiency across the feasible output range.

Second and far more consequentially, the fuel costs themselves, which are calculated by iOpt and PCI and were provided in discovery, have been recalculated using a price of $[redacted] per one million British Thermal Units (MMBtu), which appears to be some kind of average cost estimate. However, the average price for Jim Bridger fuel in (1) the final 2020 TAM study was $[redacted] per MMBtu; (2) the final 2021 TAM study was $[redacted] per MMBtu; and (3) this year's update study was $[redacted] per MMBtu. Thus, it would appear that Mr. Burgess' arbitrarily high number of $[redacted] per MMBtu was not based on any average cost information used by the Company in any of the last three TAM proceedings.

Mr. Burgess then misleadingly labeled his newly created fuel cost as "Unit 1 pac incr cost" or "Unit 2 pac incr cost" (and so on) in his work papers. Again, this "fuel cost" is not an incremental cost provided by PacifiCorp. In reviewing the information provided through discovery, I was able to back into the *actual* incremental cost included because the iOpt output files that Mr. Burgess received from the Company include both fuel cost and fuel consumption. The incremental prices that Mr. Burgess was made aware of through discovery ranged from $[redacted] to $[redacted] per MMBtu.

In summary, Mr. Burgess included a fuel cost that the Company has not used in any of the last three TAM proceedings (either on an average or incremental basis) and attempted to label it as a Company input. He performed a similar operation in the PCI analysis, which he labeled "upd coal price." None of this was explained or even alluded to in the testimony offered by Mr. Burgess.

Q. Why is this sort of misrepresentation problematic?

A. In my opinion, if Mr. Burgess wishes to alter data provided to him in discovery, he should mention those alterations in testimony. Using what appears to be an estimate of average costs, particularly average costs that haven't been used by the Company in forecasting costs during the last three TAM proceedings, is inappropriate in all sorts of ways, the most important of which is that average costs include fixed cost components. In other words, in using those costs and comparing them to the start charge, Mr. Burgess is conducting an avoided cost analysis in a way that fails to acknowledge that not all costs are avoidable. It is also worth noting that in doing so he is directly contradicting his own testimony, which concedes at least some level of fixed costs at BCC (though he refuses to use the amount provided to him in discovery by the Company).

Q. Do you agree with his conclusions?

A. Of course not. The analysis is based upon data that has been inappropriately altered.

4. Miscellaneous Issues

Q. Sierra Club argues that your example of marginal costs relating to a car trip is inaccurate and instead argues that because NPC is forward looking it "must consider all of the relevant costs."[69] Do you agree?

A. No. Sierra Club hinges this claim on the idea that the year of the mine plan and the year in which the TAM takes place are different.[70] For the sake of clarity, "the year of the mine plan" in my testimony[71] refers to the actual calendar year to which the mine plan applies. It is not intended to imply that all costs are variable until January 1, 2022, at which point many become fixed.

Q. Sierra Club also agrees with Staff that future Informational Runs should be conducted without "take or pay" adjustments.[72] Do you continue to believe that any Informational Run without such adjustments would lack informational value?

A. Yes, for the reasons stated above in my response to Staff on the same topic.

III. MARKET CAPACITY LIMITS

A. <u>Response to AWEC's Rebuttal Testimony on Market Caps</u>

Q. Does AWEC continue to reject the Company's market cap proposal?

A. Yes. However, AWEC has also proposed a complex alternative methodology targeted to specific markets if the Commission fundamentally agrees with PacifiCorp that its "sales to market (also referred to as off-system sales) are being over-forecast."[73]

---

[69] Sierra Club/200, Burgess/35.
[70] Sierra Club/200, Burgess/35; 14-16.
[71] PAC/400, Staples/ 54; 15-16.
[72] Sierra Club/200, Burgess/39.
[73] Order No. 20-473 at 130.

Q. Does AWEC agree with PacifiCorp and CUB that the Company is consistently under recovering NPC in the TAM?

A. No. AWEC argues that the Company has been "fully recovering" all of its costs "when viewed on a holistic basis" based on PacifiCorp's total return on equity.[74]

Q. Is this the proper way to assess under recovery of NPC in the TAM?

A. No. AWEC's argument ignores the indisputable fact that the Company has under recovered NPC in 12 of the last 13 years by focusing on PacifiCorp's total earnings. This sort of comparison is irrelevant in the TAM, which focuses on NPC forecasting, not the Company's total return on equity.

Q. Does AWEC believe that any modeling changes should be reserved for next year's TAM?

A. Yes. AWEC believes that "it would be more fruitful" to maintain the status quo and wait until the Aurora model is implemented to resolve modeling issues because "it is impossible to know whether any analysis adopted in this proceeding will be relevant going forward."[75] There is nothing fruitful about maintaining a broken status quo.

1. AWEC's Quantitative Analysis

Q. Does AWEC believe that the Company's analysis in its reply testimony adequately supports its market cap proposal?

A. No. AWEC finds PacifiCorp's illustrative example of the flaws of maximum market caps in Figure 3 irrelevant primarily because GRID's market caps "function as the maximum amount of sales that can be made in a particular time period at a particular

[74] AWEC/200, Mullins/3-4.
[75] AWEC/200, Mullins/4-5.

market hub, not the average."[76] Therefore, AWEC argues that a maximum value market cap does not prove that the model will produce sales above the historical average.

Q. Do you agree with the statement?

A. No. I presented evidence in Figures 4 and 5 of my reply testimony that the short-term sales variance in GRID has become more extreme in nearly every year since 2012.[77] AWEC's argument does not reflect actual modeling conditions in GRID over the past 10 years. In addition, it is an oversimplification to say that the only thing to be gleaned from Figure 3 is that "the maximum of a set of numbers exceeds the average of the same set of numbers."[78] The most important takeaway from Figure 3 is that the assumptions that the maximum value is representative of normal conditions and that all maximums will coincide in the future overestimates aggregate system liquidity, which leads to an over-forecast of sales.

Q. AWEC claims to have conducted its own analysis supporting its argument in Confidential Table 2 and Table 3.[79] Have you reviewed this analysis?

A. Yes.

Q. What is your conclusion?

A. The historical transactions that AWEC has compared its projections to are the numbers upon which the market caps are based, which is actual transaction data. However, it is actual transaction data that includes booked out volumes. This is sensible for the purpose of deriving market caps because it represents the amount of

[76] AWEC/200, Mullins/6.
[77] PAC/400, Staples/22-24.
[78] AWEC/200, Mullins/6, 9-10.
[79] AWEC/200, Mullins/6-9.

volume that could be transacted in those markets; however, applying the data as AWEC does fails to recognize that PacifiCorp did not deliver all of those volumes and did not gain all of the revenues associated with those sales. As I explain below, this is inappropriate and would not produce a forecast that would more closely match the Company's actual expectation regarding off-system sales and the associated revenues.

Q. Does AWEC critique the Company's analysis of historical sales?

A. Yes. AWEC believes that PacifiCorp's comparisons of sales in Figures 4 and 5 are "inaccurate and invalid" because they have not been adjusted for bookouts.[80]

Q. Specifically, AWEC argues that because the GRID model NPC report includes both the "imputed offsetting volumes associated with the DA/RT" and sales encompassing an "exchange transaction with the Public Service Commission of Colorado (PSCo), PacifiCorp's analysis results in an invalid comparison.[81] Do you agree?

A. To an extent. The PSCo Exchange is correctly noted by Mr. Mullins as a valid candidate to be carved out of the forecast, given that an examination of historical behavior indicates that the Company books out the volumes with great frequency. The Day-Ahead/Real-Time (DA/RT) adjustment is also composed of volumes that will be booked out in some measure. I would not concede that the DA/RT should be considered nothing but bookouts, but rather than identify the appropriate proportion, I propose to simply remove it completely from the historical forecasts for illustrative purposes. However, even when accepting the premise of AWEC's arguments, the

[80] AWEC/200, Mullins/9.
[81] AWEC/200, Mullins/10-11.

analysis plainly shows that AWEC overstates the significance of these purported adjustments.

[redacted]

[redacted]

Q. Please describe the table above.

A. Confidential Figure 3 above shows that even after removing all DA/RT Adjustment sales volumes and removing all PSCo Exchange volumes from the historical forecasts, GRID has still historically over-forecasted sales by an average of approximately 4.2 million MWh per year.

Q. What was the volumetric impact of the Company's proposed change to market caps in this year's TAM proceeding?

A. The use of average market caps reduced total sales by approximately [redacted] MWh.

Q. Does this indicate that the change in market caps will not fully solve the issue of sales over-forecasting in the TAM?

A. Yes. The Company believes that the problem of over-forecasting sales will continue even after this change, but at every step along the way, we have tried to behave in a manner consistent with both the letter and the spirit of the Commission's order in the last GRC. The Company still proposes to use gross volumes in the calculation of the market caps, and continues to only impose market caps at illiquid locations. Simply put, this is not a revolutionary change, and it fits perfectly within the confines of the Commission's direction to explore straightforward changes to limits in order to remedy the under-recovery of NPC.

Q. AWEC has also conducted a comparative analysis of historical sales included in the actual NPC report to the level of sales forecasted in GRID, with an adjustment removing bookouts.[82] Why does Figure 3 not match AWEC's analysis?

A. AWEC's analysis attempts to compare GRID outputs and actual sales after adding back booked out volumes. However, this misses the point. Doing so would imply that GRID is designed to account for bookouts in its forecast, which is not the case. As demonstrated above, even when allowing for AWEC's position that the DA/RT adjustment will result in nothing but booked out volumes and removing the PSCO exchange, we arrive at a forecast history that indicates a vast overestimation of sales. GRID's balancing purchases and sales simply do not include bookouts because the purchase price is set higher than the sales price, which prevents GRID from finding economic opportunities to buy and sell at the same location in the same hour.

[82] AWEC/200, Mullins/15-16; *see also* AWEC/202.

2. AWEC's Alternative Proposal

Q. Does AWEC acknowledge that GRID overestimates short-term firm sales at some of the Company's market hubs?

A. Yes. AWEC acknowledges that GRID tends to overestimate sales at the California-Oregon Border and Four Corners market hubs. AWEC also points out that GRID under-forecasts sales at Mead likely because of transmission constraints.[83]

Q. Based on this information, has AWEC proposed an alternative modeling approach that seeks to adjust these GRID inaccuracies?

A. Yes. AWEC proposes setting a market cap through iterative GRID runs so that the model produces results that equal, but do not exceed, the historical average for any period.[84] AWEC summarizes this approach in Table 4-REB.[85]

Q. Using this alternative method, what is the adjustment to NPC?

A. The impact of this alternative approach produces a $[redacted] decrease to NPC system-wide, or a $[redacted] reduction Oregon-allocated.[86]

Q. Does the Company have any reservations about AWEC's proposed alternative method?

A. Yes. While PacifiCorp appreciates AWEC's alternative proposal, the Company believes that the complicated iterative approach needed to employ this method is cumbersome and not in the spirit of the Commission's order, which recommended straightforward inputs or adjustments rather than "complex new adjustments."[87] In addition, AWEC's proposal suffers from the drawback of being measured against

83 AWEC/200, Mulllins/17.
84 AWEC/200, Mullins/17.
85 AWEC/200, Mullins/19.
86 AWEC/200, Mullins/19.
87 Order No. 20-473 at 130.

historical sales figures that haven't had booked out volumes removed, as noted above. Ultimately, PacifiCorp believes that its original approach aligns best with the Commission's directive.

Q. Would the Company endorse using this updated methodology in this year's TAM?

A. No. In addition to the above-mentioned concerns about whether the methodology closely matches the direction received from the Commission and whether it would ultimately produce a truly accurate forecast, there is an additional question of timing for this year's TAM proceeding. The Company is unlikely to receive an order until late October, leaving very little time to implement and carry out the approach prior to the indicative November filing. That creates an additional hurdle to AWEC's proposed methodology.

B. Response to Staff's Rebuttal Testimony on Market Caps

Q. Has Staff's position on PacifiCorp's proposed market capacity limits changed since the Company filed its reply testimony?

A. No. Staff maintains that the Company's proposal is (1) poorly supported, (2) poorly timed, and (3) based on a misinterpretation of the Commission's directive in Order No. 20-473.[88] Staff asserts that any change to market caps is premature without an exploration of the "*many* ways" to address the Company's overestimation of off-system sales in GRID.[89]

[88] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 128-131 (Dec. 18, 2020) (addressing PacifiCorp and parties requested changes to the TAM and PCAM mechanisms in the Company's last general rate case).
[89] Staff/1200, Dlouhy/2.

Q. Does Staff provide any alternative recommendations to address GRID overestimation of off system sales?

A. Yes. Staff now believes "it is possible that the current 'maximum of averages' approach is not the optimal method for forecasting off-system sales."[90] In its place, Staff proposes to use a so-called "third quartile of averages" approach for the 2022 TAM. Staff claims that this approach maintains "true market depth" while addressing PacifiCorp's concerns.[91] Under this approach, Staff revises its adjustment down to approximately $[redacted] Oregon-allocated.

Q. Is the name of Staff's alternative proposal misleading?

A. Yes. Staff labels this approach as a "third quartile" approach, but this label inaccurately describes Staff's methodology. Staff's approach blends the third and fourth quartiles of PacifiCorp's historical off-system sales to arrive at a "third quartile." To conduct an accurate third quartile approach, Staff would simply need to choose the second highest of the four observations. Staff's current proposal only slightly reduces market caps from the "maximum of averages" approach and does not adequately address the Company's persistent over estimation of off-system sales.

Q. What is your general response to Staff's arguments?

A. Staff's position disregards the near-certain reality that maintaining current market caps will contribute to significant NPC under recovery for PacifiCorp in 2022. Contrary to Staff's claims, PacifiCorp's proposed change is (1) supported by eight years of data showing that the current market caps approach consistently overestimates power costs, (2) timed to ensure more accurate power cost estimates for

---

[90] Staff/1200, Dlouhy/12.
[91] Staff/1200, Dlouhy/2-3.

2022, and (3) complies with the Commission's directive to propose straightforward changes to address sales over-forecasting.

The current "maximum of averages" methodology, the Company's "average of averages" proposal, and Staff's alternative are all variations on the same basic construct. The issue is ultimately whether the particular approach places sufficient limits on market sales to accurately simulate actual market depth and liquidity. The Company's actual experience since 2013 shows that the market caps under the maximum of averages approach are woefully insufficient and Staff's alternative—which makes only minor adjustments to the current approach—is similarly inadequate. Returning to the original "average of average" approach for 2022 is the best option for realistically modeling actual market conditions for off-system sales.

3. History of the "Maximum of Averages" Approach

Q. Does Staff question the validity of the "average of averages" approach proposed by PacifiCorp?

A. Yes. Staff argues that despite PacifiCorp's persistent overestimation of off-system sales since the Commission adopted the "maximum of averages" approach in docket UE 245, the Commission should not return to the "average of averages" approach "that was known to be problematic."[92]

Q. Is this an accurate characterization of the Commission's resolution of the issue in the 2013 TAM, docket UE 245?

A. No. While Staff and AWEC (then the Industrial Customers of Northwest Utilities (ICNU)) made arguments to remove market caps entirely in the 2013 TAM, the

[92] Staff/1200, Dlouhy/7.

Commission observed that "market caps have always been part of GRID and neither Staff nor ICNU persuasively argue that GRID, as it currently exists, no longer needs market caps."[93] Critically, the Commission noted that neither Staff nor ICNU asserted that GRID would "function perfectly" without market caps.[94] Even though the Commission—at the time—believed that the "maximum of averages" approach was "superior" to the "average of averages" approach, it did not foreclose the issue for future TAMs or affirmatively state that the "average of averages" approach was fundamentally flawed or unreasonable.[95] Instead it made clear that properly functioning market caps were important for accurately modeling NPC in GRID.

Q. Did the Commission address problems related to the "maximum of averages" approach in PacifiCorp's last general rate case?

A. Yes. The Commission directly addressed the significance of its 2013 market cap decision in the Company's 2020 General Rate Case, docket UE 374. After recognizing the importance of the DA/RT adjustment to improve PacifiCorp's forecast,[96] the Commission further stated that the Company could continue to improve the accuracy of its forecast with "straightforward inputs or limits," citing the over forecast of off-system sales as a place for forecast improvement.[97] The Commission signaled a willingness to address PacifiCorp's persistent under recovery of NPC through TAM adjustments that improve forecast accuracy.

---

[93] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Transition Adjustment Mechanism,* Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012) [hereinafter 2013 TAM].
[94] 2013 TAM, Order No. 12-409 at 7.
[95] *See* 2013 TAM, Order No. 12-409 at 7-8.
[96] Order No. 20-473 at 130.
[97] *See* Order No. 20-473 at 130.

Q. Staff argues that Order No. 20-473 allows PacifiCorp to address these modeling changes at any time between now and 2024.[98] Does this fact preclude the Company addressing the issue in this proceeding?

A. No. Staff's underlying point here seems to be that because PacifiCorp will switch to Aurora in 2023, the adjustment to market caps is unnecessary in 2022. But as I stated in my reply testimony, this argument is irrelevant in this proceeding, where the Company will not be able to accurately forecast NPC in GRID without this change to market caps.[99] Nothing in Order No. 20-473 prohibits the Company from addressing its persistent under recovery in this proceeding and the Commission's order does not require PacifiCorp to under recover in 2022 simply because COVID-19 delayed its switch to Aurora.

Q. Staff also points out that the Company does not need to "restrict" itself to "simple methods" under the Commission's directive.[100] Do you agree?

A. Not really. The Commission stated that PacifiCorp "does not necessarily need to develop a complex new adjustment," signaling that PacifiCorp could expeditiously propose remedial modeling changes.[101] Furthermore, Staff contradicts its own point when it boasts that the proposed alternative "third quartile of averages" approach is an "easily replicated" "simple solution" to over estimation of off-system sales.[102]

---

[98] Staff/1200, Dlouhy/10.
[99] PAC/400, Staples/20-21.
[100] Staff/1200, Dlouhy/10.
[101] *See* Order No. 20-473 at 130.
[102] Staff/1200, Dlouhy/16.

Q. Finally, Staff suggests that because the Commission did not directly mention market caps and did mention "other options" in Aurora, the Company should not address market caps in this proceeding.[103] Is this an accurate reading of Order No. 20-473?

A. No. Once again Staff seems to be suggesting that the Commission's directive requires PacifiCorp to wait until it switches to Aurora to address its under recovery of NPC through over forecasting of off-market sales. Nothing in the Commission's order suggest such a conclusion. In fact, the Commission points out that the TAM is an *annual filing* and "PacifiCorp has an annual opportunity to improve its forecast."[104] While the Company can continue to explore further opportunities to improve NPC forecasting through the upcoming Aurora workshops and subsequent TAMs, it is also entitled to forecast accurate NPC for 2022.

4. Analytical Support for PacifiCorp's Proposal

Q. What does Staff believe that the Company would need to adequately support the adoption of the "average of averages" approach?

A. Staff believes that PacifiCorp would need to provide a time series of (1) actual off-system sales from 2013 to 2020, (2) projected off-system sales from 2013 to 2020 using the "maximum of averages" approach, and (3) projected off-system sales from 2013 to 2020 using the "average of averages" approach. According to Staff, the data would also need to be run through Aurora in this proceeding to make the change precedential.[105]

[103] Staff/1200, Dlouhy/11.
[104] Order No. 20-473 at 130.
[105] Staff/1200, Dlouhy/8.

Q. Has PacifiCorp provided any of this information already in this proceeding?

A. Yes. The Company has provided a time series of actual off-system sales and a comparison of these sales to projected off-system sales using the "maximum of averages" approach to show the "gross over-estimation of the sales benefit" Staff found in its similar study in docket UE 374.[106]

Q. Why hasn't PacifiCorp conducted a time series of each GRID run from 2013 to 2020 using the "average of averages" approach?

A. Running such a series of studies would be onerous and would not provide additional analytical insight. As shown in Figure 4 of my reply testimony, sales have been consistently over-forecasted over the course of the past eight years. As shown in Figure 3 above, even removing the portions of the forecast that AWEC contends will eventually be booked out still results in a large over-forecast of sales. Reducing market caps and reducing the sales forecast by definition as a result of that reduction to market caps would have inherently made the forecasts more accurate. As discussed above, the change to market caps proposed by PacifiCorp in this proceeding will likely reduce the amount of the sales over-forecasted, but is almost certain not to eliminate it completely.

Q. Would running these time series through Aurora provide any relevant information for this proceeding?

A. No. Aurora is not at issue in this proceeding and any runs through Aurora would have no bearing on NPC forecasts for 2022. Once again, the Company should not be

[106] Docket No. UE 374, Staff/2400, Gibbens/19-22.

forced to over-forecast off-system sales in this proceeding because it expects to shift to a new model in 2023.

Q. Staff also claims that PacifiCorp's responses to data requests have not helped Staff support their position.[107] Please respond.

A. The Company made plain in its response to Staff Data Request 15 that the information contained therein was not comparable to the actual purchase and sales data provided in response to Staff Data Requests 2 and 4 (a fact that Dr. Dlouhy acknowledged in his rebuttal testimony).[108] The Company is required to answer the questions asked of it, not the questions it would prefer were being asked. We may sometimes include comments like the one in response to Staff Data Request 15 as a means by which to inform Staff of potential issues with their approach, but we do not know with any certainty how they plan to use the data so we do so with the hope that Staff will follow up in another request, ask for a supplemental response, or simply request a brief phone call to discuss the relevant details. PacifiCorp strives to make our interactions with Staff as productive as possible. In this case, Staff simply made no attempt to address something that the Company made them aware of in the response we provided.

Q. Staff believes that the data supplied by the Company in Data Request 15 "points to a completely different result" than PacifiCorp's analysis in Table 4 of your testimony.[109] Can you resolve this discrepancy?

A. Yes. As pointed out in my reply testimony, bookout volumes do not belong in an

[107] Staff/1200, Dlouhy/11-12.
[108] Staff/1200, Dlouhy/ 11, 10-13
[109] Staff/1200, Dlouhy/12.

analysis comparing forecasted sales to actual sales. Delivered sales volumes are the most useful point of comparison.

5. The "Third Quartile of Averages" Approach

Q. How does Staff describe its alternative "third quartile of averages" approach?

A. Staff supports "using the third quartile of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[110] Staff then averages the highest and second highest observed averages to reach its proposed market cap.

Q. Does this approach accurately describe what you would consider a third quartile approach?

A. No. It is not a third quartile approach, which would simply be selecting the second highest of the four values.

Q. Staff suggests that this approach "will lead to a market cap that is greater than or equal to the 'average of averages' approach."[111] Do you agree?

A. Yes; but using Staff's methodology for the market cap will be much closer to the "maximum of averages" approach rather than the "average of averages" approach. Staff seems to suggest that its approach is an equal compromise between the Company and Staff's positions. In reality, Staff simply seeks to blend the two most extreme values instead of using the single most extreme value, as it has proposed in the past.

Q. Is Staff's approach more accurate than the one proposed by PacifiCorp?

A. No. As demonstrated above, even if one accepts AWEC's position on the DA/RT

[110] Staff/1200, Dlouhy/14.
[111] Staff/1200, Dlouhy/15.

adjustment and PSCo Exchange contracts, adjusting those out of the GRID forecast still results in a historical over-forecast of sales that dwarfs the impact of the proposal put forth by the Company in this case. Accepting Staff's methodology would do virtually nothing to address the issue highlighted in the Commission's order.

6. Miscellaneous Issues

Q. Staff also points out that the Company's acknowledgement that the "average of averages" approach is used in other states in which PacifiCorp operates has no bearing on its use in Oregon.[112] Do you agree?

A. No. While I do agree that another state commission's evaluation is not precedential in Oregon, it does lend credibility to the "average of averages" approach as a workable, time-tested methodology. If the "average of averages" approach was so restrictive and problematic that it resulted in gross under estimation of off-system sales, other states would have likely addressed this issue long ago.

Q. Staff also argues that the whole intent of the Company market cap is to "model what can *possibly* be sold at a market hub" making the most extreme outlier the most appropriate value.[113] Do you agree with this characterization of market caps?

A. No, and this suggestion goes against the entire purpose of NPC forecasts in the TAM, which is to accurately model PacifiCorp's actual NPC.[114] As the Commission noted in the 2013 TAM, the primary purpose of market caps is to simulate real-world inputs that GRID cannot account for, such as load requirements, transmission constraints,

[112] Staff/1200, Dlouhy/19.
[113] Staff/1200, Dlouhy/19-20.
[114] *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) (stating that the goal of the TAM is to "achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.").

and market illiquidity.[115] Staff's suggestion here goes against the core assumptions of TAM modeling.

Q. Does PacifiCorp's criticisms of Staff's and AWEC's analysis contradict each other, as Staff suggests?[116]

A. My reply testimony did not accept the validity of AWEC's claims that the DA/RT adjustment represents a large amount of booked out volumes that are included in the forecast. Further consideration has made me willing to acknowledge that the DA/RT adjustment does include at least some volumes that will eventually be booked out. As demonstrated above, the impact of reducing the forecast by a like amount is immaterial to the question of whether GRID over-forecasts sales as a result of the historical market cap approach required in the TAM.

C. Response to CUB's Rebuttal Testimony on Market Caps

Q. Has CUB's position on market caps changed since its direct testimony?

A. Somewhat. CUB still acknowledges that the Company has been over forecasting off-system sales in prior TAM proceedings but believes that the Company's suggestion that market caps are the only culprit is misguided.[117] CUB argues that other factors also help explain the Company's over forecasting, including weather variances and PacifiCorp's shifting resource base. CUB also believes that the development and expansion of the EIM and the Company's focus on sales volumes and revenues overstates the claimed forecast errors. Finally, CUB argues that any 2020 data will be unreliable because of the COVID-19 pandemic.[118]

---

[115] 2013 TAM, Order No. 12-409 at 7.
[116] Staff/1200, Dlouhy/21.
[117] CUB/200, Jenks/2-3.
[118] CUB/200, Jenks/3.

Q. CUB argues that GRID's assumption of normalized weather could also account for some of the inaccuracies in forecasting off-system sales.[119] Do you agree?

A. Yes, but creating an adjustment for non-normalized weather conditions is practically impossible. Making weather adjustments would also be much more complicated than the Company's proposal and would have a less than straightforward modeling effect.

Q. CUB also argues that while GRID over forecasts sales more than purchases, the difference becomes less severe if one accounts for the larger margins for short-term sales.[120] Is this accurate?

A. No. The primary issue with CUB's analysis is that Mr. Jenks attempts to calculate a *margin* on sales and compare that to the *expense* (not margin) for purchases. This is not an apples-to-apples comparison. Further, the expenses incurred to generate for the purpose of making sales are quite specific, not average. The generation costs avoided by making purchases are similarly specific, assuming that generation costs are even being avoided (many purchases are needed to serve load). Those specific expenses and avoided costs are both included in the GRID forecasts for each TAM year, and a comparison of those forecasts to actual NPC yields a series of large under-recoveries, driven in part by overestimated sales revenue forecasts that cannot be realized in actual operations.

Q. CUB argues that PacifiCorp's data showing over-forecasting of short-term sales needs to be examined in the context of the EIM.[121] Is this necessary?

A. No. Equating EIM exports with market sales could logically close the gap between

[119] CUB/200, Jenks/3-5.
[120] CUB/200, Jenks/6-7; *see also* CUB/102.
[121] CUB/200, Jenks/7-8.

the Company's observed historical sales and the much higher levels of sales that it has been forced to forecast because of the maximum market cap approach. However, including both the sales revenue for GRID sales forecasts that are later replaced by EIM transfers, *and* including the EIM benefits themselves would constitute a double counting of benefits. One or the other would still need to be reduced after the proposed re-examination. The Company's approach of simply revising the market cap input with the goal of producing a more reasonable sales forecast is more straightforward and allows for easier back testing against actuals in order to assess the methodologies.

Q. CUB argues that the Company's 2020 data "is of very little use for predicting future sales and purchases."[122] Do you agree?

A. No. Every year has supply and demand fluctuations that can make profound differences on power costs during that year. As described above, historically low gas prices in 2016 and high hydro generation in 2017 led to unpredicted economic cycling. In contrast, low hydro generation in 2021 coupled with a historic northwest heat wave led to high power costs despite the ongoing COVID-19 pandemic. The intent of using historical averages in power forecasting is to ensure that while anomalies will invariably occur, the average should serve to normalize NPC. If CUB and other stakeholders begin to pick and choose which years they would like to include in a "average," the numbers will be skewed by definition.

[122] CUB/200, Jenks/8-9.

Q. CUB continues to believe that PacifiCorp is poised to increase short-term power sales because of the Company's shift towards renewables compared to other power sellers on the system.[123] Do you agree?

A. No. The Company has made investments in renewable resources to cost-effectively serve customers, not to operate them as merchant generators.

Q. But CUB points out that the Company's new wind resources in the 2022 TAM led to [redacted] MWh of balancing sales, earning the Company $[redacted].[124] Has CUB taken these numbers out of context?

A. Yes. First and foremost, those resources exist to cost effectively serve customers. In the study cited by CUB, GRID generated a small portion of the savings [redacted] on a total-company basis) by increasing sales, but the overall savings from the inclusion of the Energy Vision 2020 resources was approximately $[redacted] on a total-company basis, indicating that other factors far outweigh the incremental sales revenue. One factor that deserves consideration when examining the Company's recent sales history is that PacifiCorp is hardly the only entity introducing large amounts of renewable generation to its system. When the Company's resources are exceeding forecast, it is quite likely that the resources of others are performing in a similar fashion, which can have the effect of depressing prices and making sales a less attractive or economic option.

Q. Based on all these competing factors, does CUB propose an alternative to the Company's market cap proposal?

A. Yes. CUB believes that the "average of averages" approach is too restrictive and

---

[123] CUB/200, Jenks/9.
[124] CUB/200, Jenks/10.

therefore proposes setting the market cap at the mid-point between the "average of averages" and the "maximum of averages."[125]

Q. Does this approach suffer from flaws similar to Staff's "third quartile of averages" approach?

A. Yes. As mentioned above in my response to Staff's proposal, the evidence would suggest that even the approach favored by the Company is unlikely to fully address the over-forecasting of sales in the TAM, so an approach that has a smaller impact on the forecast will, by definition, be less accurate.

IV. OTHER ADJUSTMENTS

A. <u>QF Contracts</u>

Q. Does Staff continue to support an adjustment to QF power costs based on historical overestimation?

A. Yes. Staff continues to believe that its $[redacted] Oregon-allocated adjustment is "sound and reasonable."[126] While Staff acknowledges that the Company's QF overestimations have reduced since the adoption of the contract delay rate, it maintains that a [redacted] overestimation "is still significant for the purpose of setting TAM rates."[127]

Q. Staff claims that PacifiCorp is not using the best information available to forecast its QF costs.[128] Is that accurate?

A. No. For renewable QF contracts with a nameplate capacity greater than 10 megawatts, the Company forecasts capacity based on the P50 in the QF

[125] SUB/200, Jenks11-12.
[126] Staff/1100, Zarate/3.
[127] Staff/1100, Zarate/2.
[128] Staff/1100, Zarate/3.

developer's interconnection agreement for all facilities that have connected in the past four years. Once the facility has been interconnected for four years, the Company forecasts capacity based on the actual history of the QF.

Q. Is Staff's approach consistent with how PacifiCorp forecasts generation for its owned renewable facilities?

A. No. PacifiCorp forecasts owned generation based on the developer's forecast during the first four years of operation, then uses a historical capacity factor thereafter. Staff has taken the position in the past that the P50 forecasts should be used (which decreases NPC) for owned generation,[129] while arguing against their use for QFs (which tend to increase NPC). This is inconsistent and appears calibrated to opportunistically reduce NPC. If these developer forecasts represent the best information that is available to PacifiCorp regarding their owned resources, then that information should be applied to QFs as well in the TAM forecast.

B. <u>EIM Benefits Allocation Factor</u>

Q. Does Staff have any concerns about the Company's proposal to shift from System Generation to System Energy for PacifiCorp's EIM benefit allocation factor?

A. Yes. Staff believes that this change is unwarranted because (1) it represents a new issue raised too late into the case, (2) it should be addressed in the Company's MSP, (3) the change conflicts with the 2020 Interjurisdiction Cost Allocation Protocol, and (4) PacifiCorp does not adequately support the recommendation.[130]

[129] *In the Matter of PacifiCorp d/b/a Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE-356, Staff/100, Gibbens/23 (June 10, 2019).
[130] Staff/1000, Enright/6-9.

Q. Do any other parties oppose the shift?

A. Yes. CUB also believes that addressing this shift late in this year's TAM sets bad precedent and believes that the allocation process should be addressed through the MSP.[131]

Q. After reviewing the testimony of Staff and CUB, has PacifiCorp reconsidered its proposal?

A. Yes. The Company will remove this EIM allocation factor shift from this proceeding and plans to address this issue in PacifiCorp's next round of MSP negotiations.

C. <u>Other Revenues</u>

Q. Has AWEC's position changed regarding its adjustment to Other Revenues?

A. Not substantially. AWEC continues to believe that fly-ash sales should be included in the TAM because fly-ash sales are directly tied to the production at PacifiCorp's coal plants. However, AWEC notes that the Company seems to have increased its revenue on fly-ash for the first quarter of 2021. Accordingly, AWEC suggests using fly-ash sales from the prior year to calculate NPC in the TAM forecast.[132]

Q. Have any other parties addressed this issue or the Company's inclusion of the Stateline Contract expiration?

A. Yes. Staff is concerned that PacifiCorp "has taken a selective approach in updating its Other Revenues" in contravention of the 2011 TAM, Order No. 10-363.[133] Nonetheless, Staff would support the $3 million reduction to Other Revenues due to the expiration of the Stateline Contract on the condition that the Company ensure any

---

[131] CUB/200, Jenks/22-24.
[132] AWEC/200, Mullins/24-25.
[133] *In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363, App'x A at 4 (Sept. 16, 2010).

new contacts that may increase Other Revenues are included in the indicative November filing.[134]

Staff also supports AWEC's position on fly-ash sales. Staff believes that the inclusion of fly-ash in the TAM (1) ensures benefits are captured fully and (2) reduces the risk of sales underestimation in PacifiCorp's next general rate case.[135] Staff also supports AWEC's proposal to base fly-ash sales off calendar year 2020 for the 2022 TAM, adjusted to reflect Cholla's retirement.[136]

Q. What was the purpose of the other revenue adjustment?

A. Staff first proposed the other revenue adjustment in the 2011 TAM and described it the following way:

> In non-general rate case years, in which only a power cost update is filed, the Company is allowed to include or update the costs associated with new resources, contracts and existing facilities for services that it is providing to a third party entity. With the update or inclusion of these new costs there can also be a corresponding change in revenue. If these revenues are accounted for as "other revenue" they currently go un-recognized in rates. This mismatch between updating costs and revenues is unreasonable.[137]

The other revenue adjustment was specifically intended to match updated costs for services provided to a third-party entity with the revenues it receives for those services. The settlement in the 2011 TAM identified the specific revenue items to which this situation applied.[138] The only remaining one of these contracts is the Stateline Contract, which expires this year.

---

[134] Staff/1000, Enright/11.
[135] Staff/1000, Enright/11.
[136] Staff/1000, Enright/11.
[137] *In the Matter of PacifiCorp, d/b/a/ Pacific Power, 2011 Transition Adjustment Mechanism*, Docket UE-216, Staff/100, Brown/14 (May 12, 2010).
[138] Order No. 10-363, Appendix A, Exhibit B.

Q. Staff contends that the update related to the Stateline Contract is a selective update to other revenues. Do you agree?

A. No. It was an error in the direct filing that occurred because of a miscommunication. PacifiCorp is simply correcting that error.

Q. Didn't the Commission already include fly-ash sales in the Company's revenues as part of the 2020 General Rate Case?

A. Yes. As AWEC acknowledges, the Commission included $[redacted] in fly-ash sales in base rates in the Company's last general rate case.[139]

Q. Is fly-ash traditionally included in the Federal Energy Regulatory Commission (FERC) accounts identified in the TAM guidelines?

A. No. Attachment A identifies the specific subset of FERC accounts that are included in the TAM. PacifiCorp does not reflect fly-ash sales in those accounts. In fact, fly-ash sales are reflected in FERC account 456.

Q. If fly-ash sales were not contemplated to be included in other revenues and are not included in the FERC accounts identified in the TAM guidelines, is it appropriate to include them now?

A. No. Just like many other elements in base rates, fly-ash production (but not necessarily fly-ash sales) may fluctuate based on how often our plants generate. However, there are other elements like chemical costs that fluctuate based on generation that still remain in base rates. Identifying a single variable to pull out of base rates to include in the TAM, when it has not traditionally been included in the past solely because it will reduce NPC is not appropriate.

[139] AWEC/200, Mullins/24.

Q. Does the Commission normally remove revenues from base rate calculations and into the TAM outside of a change to TAM guidelines in a general rate case?

A. No. As discussed in my reply testimony, if AWEC and now Staff want to shift calculations of fly-ash sales into the TAM they must do so through a change to the TAM Guidelines in the Company's next general rate case.

Q. What is your recommendation?

A. The Commission should reject Staff's and AWEC's proposal.

V. 2023 TAM FILING DATE

Q. Does CUB continue to recommend moving up the 2023 TAM filing date?

A. Yes, although CUB changed its proposed filing date change to March 1, 2022, instead of January 15, to allow the Company to implement the December 31 forward price curve in its NPC forecasts.[140]

Q. Do any other parties support CUB's proposal?

A. Yes. Staff also supports an early filing of the 2023 TAM based on the Company's switch to Aurora.[141] However, Staff supports an earlier filing date of February 14, 2022, based on the Company's filing of the 2021 TAM on that date last year.[142] Staff then recommends allowing the Company to file an update on April 1, 2022 with updated inputs.

Q. Would an April 1, 2022 update be appropriate?

A. No. An April 1, 2022 update would use the same price curve as a filing in February or March, and as a result would provide limited value.

[140] CUB/200, Jenks/21-22.
[141] Staff/1000, Enright/13.
[142] Staff/1000, Enright/14.

Q. Is PacifiCorp amendable to holding workshops on the new model for stakeholders?

A. Yes, but there is a trade-off between pre-filing workshop and moving up the schedule. As the schedule moves earlier in the year, the Company is less able to hold workshops before the TAM is filed. As a result, workshops may need to occur after PacifiCorp files the TAM. Additionally, the administrative burden of Staff and CUB's recommended course of action remains a point of concern for the Company.

Q. Does an earlier TAM filing place a greater difficulty on PacifiCorp's ability to calculate the transition adjustment?

A. Yes. If the Commission were to order PacifiCorp to make an earlier TAM filing, PacifiCorp would request that it still provide the Transition Adjustment sample calculation for Schedule 294 on May 15 and the Transition Adjustment calculation for Schedule 296 on May 30 consistent with an unadjusted TAM schedule. With the transition to Aurora, these calculations would require some additional time.

Q. Does that conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/1100
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Michael G. Wilding

August 2021

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/1101 — PacifiCorp’s Response to OPUC Data Request 135 and 136

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Vice President, Energy Supply Management (ESM).

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. As Vice President, Energy Supply Management, my responsibilities include directing PacifiCorp's front office organization or ESM in commercial and trading activities. ESM is responsible for commercially managing PacifiCorp's diverse generation portfolio. This includes the electric and natural gas hedging, term and day-ahead trading, real-time trading and system balancing. Prior to assuming my current position in February 2021, I worked on various regulatory projects including general rate cases, the multi-state process (MSP), and net power cost filings. I have been employed by PacifiCorp since 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Utility Commission of Oregon (Commission), and the public utility commissions in California, Idaho, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. My testimony responds to Staff's testimony on the Nodal Pricing Model (NPM) and explains why Staff's adjustment is inappropriate, based on a misunderstanding of the Company's modeling of net power costs (NPC), and is a disallowance of prudently incurred costs from the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). Staff recommends that the Company reduce its total company NPC forecast by $8.4 million, an amount equal to the NPM costs, as a proxy for the benefits realized from the NPM or that the Commission direct the Company to perform a transition adjustment mechanism (TAM) model run with the same inputs as Generation and Regulation Initiative Decision Tool (GRID), using the Aurora model, for consideration in the 2022 Power Cost Adjustment Mechanism (PCAM).[1] The Commission should reject both of Staff's recommendations.

III. NODAL PRICING MODEL

Q. Please describe Staff's primary adjustment related to the NPM?

A. Staff is proposing a disallowance of the costs in the investment of the NPM by haircutting NPC by an amount equal to the NPM costs.[2] Staff refers to this as an adjustment for the NPM benefits.[3]

Q. Has Staff produced any quantification or analysis of its NPM benefits adjustment besides simply making it equal to the NPM costs?

A. No. Staff has not come forward with any evidence establishing the existence and level of incremental NPM benefits in this TAM.

Q. Will you please briefly describe the NPM?

A. The NPM is a Framework Issue in the 2020 Protocol and is the anticipated allocation

[1] Staff/1300, Gibbens/6-7.
[2] *Id.* at 6.
[3] *Id.*

methodology used for the inter-jurisdictional allocation of NPC. The 2020 Protocol defines NPM as "a method for pricing electricity proposed by the Company that is based on the marginal cost ($/MWh) of serving the next increment of demand at a given pricing node consistent with existing transmission constraints and the performance characteristics of resources."[4] To have the information necessary (i.e., day-ahead, hourly locational marginal prices (LMP)) to allocate actual NPC using the NPM, the Company contracted with the California Independent System Operator (CAISO) to receive optimized day-ahead advisory schedules that are used to inform the Company's day-ahead schedules. In other words, the NPM consists of two components: (1) the operational, "dispatch", or day-ahead schedules from CAISO; and (2) the allocation methodology.

Q. Staff contends that PacifiCorp has implemented the NPM.[5] Is this accurate?

A. When Staff is referring to NPM, they may be referring to the process by which PacifiCorp receives day-ahead schedules from CAISO. This process was implemented in January 2021. However, the Company has not yet fully implemented the NPM described above.

Q. When will the NPM be fully implemented?

A. The NPM is a Framework Issue in the 2020 Protocol and is currently part of the ongoing Multi State Protocol (MSP) negotiations. Though there are still items that need to be resolved in MSP, the 2020 Protocol contemplates that the NPM will be used for cost allocation beginning 2024.

---

[4] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/101, Appendix A at 5-6 (Dec. 3, 2019).
[5] Staff/1300, Gibbens/2.

Q. Does the Company currently have any experience, besides the NPM, with any sort of "nodal dispatch"?

A. Yes. The Company participates in the Western Energy Imbalance Market (EIM). CAISO's market model it uses to dispatch the EIM footprint within the hour is a power flow nodal model. There are two main differences between the EIM and NPM power flow nodal models. First is the period for which the optimization occurs, EIM is within the hour and the NPM is the day-ahead. Second is the footprint or area for which the optimization occurs, EIM co-optimizes all EIM participants and the NPM only optimizes PacifiCorp's system.

Q. Please describe the day-ahead set-up process.

A. Generally speaking, every morning before trading, ESM runs the Gentrader optimization model to inform day-ahead trading, day-ahead generation schedules, and NPM bids. NPM bids are submitted to CAISO by 10:00 a.m. each morning. Around 1:00 p.m. CAISO provides ESM with the advisory day-ahead dispatch schedule. ESM then will use these schedules to create the bids for the EIM market. Results are reviewed daily for discrepancies between NPM and Gentrader and either adjustments in Gentrader are made or if it appears to be a CAISO error, a dispute ticket is created with the CAISO.

Q. Please describe the Gentrader optimization model you discuss above.

A. As part of continuous improvements and in coordination with the NPM implementation, ESM transitioned to a new system optimization model called Gentrader which is owned by Power Costs, Inc. (PCI). During the implementation of NPM, PCI worked closely with CAISO and PacifiCorp to ensure the optimization results from Gentrader were consistent with the NPM. To ensure that the Gentrader optimization was consistent with NPM it was critical to have the topology right. CAISO uses the same proprietary market optimizer for the NPM as it does for its day-ahead market, which is a flow based nodal model or nodal topology that produces a LMP at each node. The Gentrader model uses a zonal topology that is restricted to PacifiCorp's transmission scheduling rights.

Q. Has PacifiCorp explained this process to Staff in this proceeding?

A. Yes. PacifiCorp has responded to Staff data requests to provide an explanation of this process. These data requests are attached as Exhibit PAC/1101.

Q. With this background, what are the operational benefits of NPM?

A. As I have previously testified in other proceedings, the benefits from nodal dispatch and NPM come from having more efficient day-ahead setup.[6] This is the result of the NPM providing ESM more transparency into PacifiCorp's transmission scheduling rights, resulting in a more granular day-ahead setup. Put another way, a more efficient day ahead set-up results in fewer changes between the day-ahead setup and real-time dispatch and thus lower NPC from avoiding those changes. Notably, as I have also testified before, this benefit is impossible to track because it is impossible to know what the day-ahead setup would be without NPM.[7]

[6] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/300, Wilding/11 (Dec. 3, 2019).
[7] *Id*.

Q. Staff continues to advocate for an adjustment to the NPC forecast to effectively disallow the costs of NPM described above (by imputing a fully offsetting benefit). Is this an appropriate adjustment?

A. No. Staff's position is that because the GRID model uses a zonal topology, the GRID model is not able to capture the benefits of having a more efficient day-ahead set-up and therefore proposes an adjustment to NPC equal to the costs of NPM. Staff mischaracterizes the operational benefit of having fewer changes between the day-ahead setup and real-time as incremental to the GRID model when in fact these benefits are not incremental. For these operational benefits to be incremental, the GRID model would have to include costs associated with changes between the day-ahead setup and real-time dispatch.[8] However, there are no costs included in the forecast for unexpected changes between day-ahead and real-time because the GRID forecast is based on a single balancing step and a single set of inputs. Put another way, GRID optimizes the system one time based on the single set of inputs and therefore does not attempt to forecast the costs that would be avoided by a more efficient day-ahead setup. It is inappropriate to input an adjustment for a benefit based on an avoided cost that is not included in the NPC forecast in the first place.

Q. How does this compare to the benefits associated with the more efficient intra-hour dispatch gained through participation in EIM?

A. The GRID model is an hourly model and does not include intra-hour changes to things like load and generation, and therefore, there are no costs in the GRID forecast

[8] These changes include things like actual loads being above or below what was expected in the day-ahead setup, wind and solar generation being above or below what was expected in the day-ahead setup, and unexpected plant outages that were not planned for in the day-ahead setup.

for those intra hour changes. Because EIM is an intra-hour market, the optimization occurs within the hour and the benefit of more efficient dispatch gained through EIM participation is avoiding some of the costs associated with those intra-hour changes. As noted in the reply testimony of Mr. Douglas R. Staples, the Commission decided against any sort of adjustment to the GRID model to account for the EIM benefits associated with more efficient intra-hour dispatch.[9] Similarly, it is not appropriate to make an adjustment for NPM.

Q. Does the treatment of EIM start-up costs and benefits in dockets UE 287 and UM 1689 support the imputation of NPM benefits as Staff alleges?

A. No. First, the Company never disputed that, aside from intra-hour dispatch benefits already captured in GRID, EIM would produce other benefits incremental to normalized NPC, such as the benefits from transfers with other EIM participants. In contrast, there are no similar incremental benefits associated with NPM. Second, Staff fails to mention that the proposal to offset EIM start-up costs and benefits was a "compromise" in a settlement agreement in dockets UE 287 (the 2015 TAM) and UM 1689.[10] Thus, Staff's sole support for imputing an $8.4 million NPM benefit is a non-precedential stipulation.

[9] PAC/400, Staples/79-80.
[10] *In the Matters of PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism and Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market,* Dockets UE 287 and UM 1689, Order No. 14-331 (Oct. 1, 2014).

Q. Staff points to the fact that GRID is a zonal model, or uses a zonal topology, as the reason why there needs to be an adjustment made to the GRID forecast. How do you respond?

A. The topology of the model should not be an issue in this proceeding. While Staff describes the differences between a power flow nodal model and a zonal model, they imply that a zonal model does not account for transmission constraints. PacifiCorp's transmission rights between zones are a binding constraint in the GRID model optimization. In fact, in Confidential Figure 1 of Staff 1300, though not shown, each of the arrows between the zones has a number with it representing PacifiCorp's transmission rights. Furthermore, zones represent an aggregation of areas of load and/or generation where there is no transmission congestion.

Q. Has Staff provided any evidence that the zones used in GRID are not accurate, meaning transmission congestion exists within the zones used in GRID?

A. No. GRID's topology accurately reflects the binding transmission constraints on PacifiCorp's system and Staff has not provided any evidence that there is transmission congestion inside any of the zones used in GRID.

Q. How does Aurora fit in with NPM?

A. The switch to the Aurora model was necessary to accommodate NPM as contemplated in the 2020 Protocol and perform the allocation of state-specific NPC for ratemaking purposes. The Aurora model provides a locational pricing output that is not available in GRID but is necessary for regulatory proceedings that use an NPC forecast, such as the TAM.

Q. Please describe the topology in the Aurora model.

A. First and foremost, the topology of Aurora is fundamentally an issue for next year's TAM when PacifiCorp actually files a NPC forecast using the Aurora model. In implementing the Aurora model the topology was built with the NPM in mind. It is important to note that Aurora is not using a nodal topology as it was not feasible for multiple reasons.

Q. Staff provides an alternate recommendation that would compare an Aurora forecast to the current GRID forecast for later review in the 2022 PCAM. How do you respond?

A. This alternate recommendation is a red herring. There is not sufficient time in this proceeding for the Company to produce an Aurora forecast using the same inputs as the GRID forecast, let alone time for the Commission to review. Additionally, even if the Aurora forecast produces lower NPC, that would not demonstrate that the NPM reduces already-normalized NPC, it could be due to any of the numerous changes associated with moving from GRID to Aurora. Finally, how that Aurora forecast would be used in the PCAM is unclear as I have already testified that the benefits of NPM are embedded in actual NPC.

Q. Has the purpose of the NPM been discussed previously with stakeholders and the Commission?

A. Yes. In the NPM Memorandum of Understanding (MOU), it was clear that the purpose was to "track the costs and benefits associated with different resource portfolios used to serve PacifiCorp's load in each state."[11] In my testimony in

[11] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/101, Appendix D at 2 (Dec. 3, 2019).

docket UM 1050, I further described that "[t]he NPM is intended to and is being developed to help preserve the benefit of operating as a single system while providing states the flexibility to have unique resource portfolios that align with a state's energy policy and interests."[12]

Q. What was previously stated about any secondary benefits?

A. PacifiCorp identified that there might be operational cost savings but has been clear from the beginning that "[t]he potential operational cost savings will be the result of a more efficient day-ahead setup and the cost savings will be embedded in the actual NPC. These potential cost savings will be impossible to accurately and precisely track as the calculation of such savings would rely on a counterfactual setup of the system without the NPM."[13]

Q. Did the Parties to the 2020 Protocol determine that the development of NPM was reasonable and prudent?

A. Yes. The NPM MOU states "the Parties affirm support for PacifiCorp's reasonable and prudent investment of related capital funds, related operations and maintenance expenses, and the related ongoing grid management charges to develop and implement an NPM."[14]

Q. Did any party raise an issue or concerns about PacifiCorp's representations on the benefits of NPM in docket UM 1050?

A. No. Additionally, no party raised any issues about imputing Staff's concept of these benefits into the TAM or any other power cost proceeding. Staff has previously

---

[12] UM 1050, Exhibit PAC/300, Wilding/10-11.
[13] *Id.* at 11.
[14] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/101, Appendix D at 3 (Dec. 3, 2019).

raised this issue in last year's TAM,[15] and PacifiCorp contested the adjustment.[16] The case was settled with a comprehensive settlement that did not resolve this issue.[17]

Q. Are you concerned by the fact that Staff uses the NPM cost as the dollar amount for its NPC adjustment?

A. Yes. By using the exact amount of the NPM costs, PacifiCorp is concerned that this is simply a disallowance of costs that Staff agreed were prudent,[18] and which were included as part of the 2020 Protocol.[19]

Q. What is your recommendation?

A. I recommend the Commission reject Staff's recommendation to impute NPM benefits equal to the costs of the NPM into the TAM, and their alternate recommendation to compare GRID and Aurora model runs to potentially reflect those benefits in some way through the PCAM.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[15] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Staff/100, Gibbens/10-11 (May 15, 2020).
[16] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Webb/72-76 (Jun. 9, 2020).
[17] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).
[18] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/101, Appendix D (Dec. 3, 2019) (Staff is a signatory to the 2020 Protocol and the NPM MOU).
[19] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Order No. 20-024 at 7 (Jan. 23, 2020).

Docket No. UE 390
Exhibit PAC/1101
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Michael G. Wilding

PacifiCorp's Response to OPUC Data Request 135 and 136

August 2021

UE 390 / PacifiCorp
June 1, 2021
OPUC Data Request 135

OPUC Data Request 135

Please describe the Company's day-ahead dispatch and planning process under the previously utilized zonal or non-nodal dispatch model.

Response to OPUC Data Request 135

PacifiCorp objects to this request as outside the scope of this proceeding and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, the Company responds as follows:

The Company assumes that the "previously utilized zonal or non-nodal dispatch model" refers to the time period prior to January 2021 when the nodal pricing model (NPM) went live. Based on the foregoing assumption, the Company responds as follows:

Each morning, as part of PacifiCorp's day-ahead planning process, the traders would review the model results that had been generated by the Company's mid-office the night before. The model results were used as a starting point to inform the traders of possible unit dispatch decisions. Potential assumptions that could change overnight might include changes in energy and natural gas market prices, generating unit availability, transmission availability, and electricity demand.

UE 390 / PacifiCorp
June 1, 2021
OPUC Data Request 136

OPUC Data Request 136

Please describe the Company's day-ahead dispatch and planning process under the nodal dispatch model.

Response to OPUC Data Request 136

PacifiCorp objects to this request as outside the scope of this proceeding and not reasonably calculated to lead to admissible evidence. PacifiCorp's use of the nodal pricing model (NPM) is currently a framework issue in the ongoing discussions with the parties to PacifiCorp's 2020 Protocol. Without waiving the foregoing objection, the Company responds as follows:

The Company uses the Power Costs Incorporated (PCI) optimization model to determine the best possible unit dispatch schedule to satisfy all system obligations economically for the next business day. The PCI model takes into account all the available generators' unit characteristics (Pmax, Pmin, ramp rate, fuel costs, start-up costs, etc.), system obligations (system load, bilateral transactions, reserve requirements, etc.), and key nodal prices and transmission limits in order to economically meet the Company's obligations. The day-ahead traders make the final decision to dispatch the coal-fueled units based on meeting system obligations and minimizing net power costs (NPC). Starting in January 2021, the Company began daily submittals to the California Independent System Operator's (CAISO) nodal pricing model (NPM) for its available generators, interchange schedules, loads and transmission nomograms through PCI. This daily submittal is performed Monday through Friday by 10:00 am. Typically, by 1:00 pm, based on the information provided to the CAISO, the NPM will provide a least-cost dispatch and commitment solution that takes into consideration unit availability, minimum-up and minimum-down times as well as start-up times.

REDACTED
Docket No. UE 390
Exhibit PAC/1200
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Dana M. Ralston

August 2021

TABLE OF CONTENTS

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

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the rebuttal testimony of Ms. Rose Anderson, filed on behalf of the Public Utility Commission of Oregon (Commission) Staff (Staff), Mr. Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB), Mr. Bradley G. Mullins, filed on behalf of the Alliance of Western Energy Consumers (AWEC), and Mr. Ed Burgess, filed on behalf of the Sierra Club.

Q. Please summarize your testimony.

A. My testimony demonstrates the following:

- PacifiCorp coal supply agreement (CSA) contracting practices are reasonable and prudent. The Company relies on generation forecasts that cover the entire contract term.
- The new CSAs for the Dave Johnston, Hunter and Craig plants are prudent.
- The Company continues to prudently manage the Huntington CSA, including its termination provisions. At present, there is no basis for terminating the CSA because of environmental regulations. The Company is regularly assessing both the economics of the plant and whether current or emerging regulations may create conditions that would allow the Company to successfully terminate the contract.

- AWEC's adjustment to Bridger Coal Company (BCC) costs related to over-estimations of materials and supplies expense is unsupported. First, overall BCC coal costs have been accurately forecast, meaning that offsetting factors that were not considered by AWEC largely counter its adjustment to a single cost element. Second, AWEC did not dispute that outside service costs have been consistently under-estimated to nearly the same extent as materials and supplies have been over-estimated. When considering offsetting factors (which AWEC claims to have done), AWEC's adjustment is substantially decreased.
- Sierra Club's recommendation for a heightened prudence review for CSAs with minimum take levels above 50 percent of expected generation has no factual support in the record and is contrary to reasonable contracting practices.
- Sierra Club has materially mispresented the level of fixed costs for the BCC mine. Because BCC fixed costs are substantially higher than Sierra Club claims, they cannot be avoided by reducing BCC production. Therefore, much of Sierra Club's claims of customer savings by dramatically reducing BCC production and Jim Bridger plant generation are erroneous and have no factual support in the record.
- PacifiCorp's use of BCC base and supplemental pricing is reasonable and reflects prudent mining operations.
- Sierra Club's recommendations that the Company significantly alter long-term mining operations and fueling strategies for BCC and the Jim Bridger plant

are outside the scope of the annual Transition Adjustment Mechanism (TAM), which is focused on forecasting net power costs using resources available in the single year TAM period. Sierra Club's issues are better suited for the Company's Integrated Resource Planning (IRP) process.

II. RESPONSE TO STAFF

Coal Contract Negotiations

Q. Please describe Staff's recommendation for future CSA negotiations.

A. Staff is "concerned that the Commission and stakeholders have little insight into how (or whether) the Company considers economic cycling for its thermal resources when negotiating coal contracts."[1] Based on this concern, Staff recommends that "PacifiCorp's coal contracts should not be deemed prudent unless, prior to contract execution, economic cycling is considered and the minimum take commitment level is kept as low as reasonably possible."[2]

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

A. Generally, the Company's negotiation strategy aligns with Staff's recommendation that the minimum take level should be as low as reasonably possible. But the minimum take level cannot be viewed or negotiated in isolation and without regard for other critical CSA elements, such as price, term, and contract maximums (i.e., the ability of the Company to procure additional coal if necessary for economic or reliability needs). Balancing these oftentimes competing considerations helps ensure that the resulting CSA is reasonable overall and will provide a stable and reliable fuel

[1] Staff/1400, Anderson/3.
[2] Staff/1400, Anderson/4.

supply at a reasonable price while allowing flexibility to respond to changing market conditions through shorter contract terms.

Q. How do you respond to Staff's recommendation that the Company consider economic cycling when forecasting the expected generation used to inform CSA negotiations?

A. The Company disagrees that a CSA should be per se imprudent if the Company did not expressly model economic cycling when determining the generation forecast used to inform the CSA negotiations. As discussed by Mr. Douglas R. Staples, the opportunities for economic cycling are very limited and the Company's analysis indicates that modeling economic cycling does not result in a materially different generation forecast. In other words, the minimum take level negotiated in the CSA is unlikely to be materially lower if the generation forecast used to inform CSA negotiations includes economic cycling.

Q. Is the Company willing to expressly model economic cycling in the coal generation forecasts used to inform future CSA negotiations?

A. Yes. To address Staff's concern, going forward the Company is willing to consider economic cycling in its CSA negotiations.

Q. Staff also testifies that: "For units that show potential to benefit ratepayers through economic cycling, future coal supply agreement negotiations should seek to obtain a minimum take level that would facilitate economic cycling, while also seeking the option to purchase more coal if needed to support reliability."[3] How do you respond?

A. The Company disagrees with Staff's implication that minimum take levels are necessarily a barrier to economic cycling. The Company's decision to economically cycle a coal plant is driven primarily by reliability concerns and secondarily by expected market conditions. The need to satisfy a minimum take requirement could be a consideration in certain circumstances but is unlikely to be a deciding factor when the Company is determining whether to economically cycle a specific coal unit.

Staff's recommendation also highlights the fundamental tension in its recommendation—Staff wants the Company to obtain the lowest minimum possible, while ensuring the ability to obtain more coal if required to provide reliable service. But as explained by Mr. Seth Schwartz,[4] the ability to nominate a wide range of annual coal purchases under a CSA will result in a much higher contract price to compensate for the risk of the customer reducing purchases in any year.

Q. Please describe Staff's proposal to increase transparency into the review process for new CSAs.

A. Staff recommends that in each future TAM filing, the Company provide the following:

- For every new CSA subject to prudence review, PacifiCorp should provide an in-

[3] Staff/1400, Anderson/4.
[4] PAC/500, Schwartz/15-16.

depth explanation of how the Company considered the potential for economic cycling when deciding on minimum take levels in that contract.

- A chart should be provided comparing the one million British Thermal Units (MMBtus) from the generation forecast used to inform contract negotiations to the number of MMBtus that PacifiCorp will be contractually obligated to pay for at each plant, by year.
- PacifiCorp should provide workpapers for the generation forecasts used to inform negotiations on each new coal contract introduced in that TAM filing.
- PacifiCorp should provide copies of its CSAs and affiliate mine plans.[5]

Q. Do you object to Staff's recommendations for future TAM filings?

A. The Company does not object to the majority of Staff's recommendations and can provide an explanation of how economic cycling was considered (as noted above), develop the chart Staff has requested, and provide generation forecast workpapers. Providing copies of its CSAs is more problematic because of the commercial sensitivity and highly confidential nature of those agreements. But the Company is committed to continue providing Staff and stakeholders access to CSAs as has been done in the past.

However, coal suppliers consider these contracts to be extremely sensitive, and there are significant reasons for maintaining the protections for these highly confidential documents. First, the contracts all contain confidentiality provisions that obligate PacifiCorp to maintain the confidentiality of the executed contract. Disclosure of the contracts can expose PacifiCorp to litigation and significant

[5] Staff/1400, Anderson/5-6.

potential damages. Any disclosure of the contract exposes PacifiCorp to significant potential liability and damages its relationships and reputation with its counterparties, which ultimately exposes PacifiCorp's customers to the risks of increased costs.

Second, from a competitive standpoint, disclosure of the terms of a coal supply or transportation agreement could seriously harm PacifiCorp's ability to obtain competitive terms for fuel and transportation. PacifiCorp's coal plants are all located in various coal regions in the western United States that have very limited, but highly competitive, coal markets. In several of these regions, there are very few coal suppliers and transporters to meet the Company's fuel supply requirements for its plants; several plants are captive to certain coal suppliers and have no access to rail services to reach other coal markets. Public disclosure of the contract terms would put PacifiCorp, the suppliers, the railroads, and the trucking companies involved in the provision and transportation of fuel at a competitive disadvantage.

Q. Does the modified protective order provide the appropriate balance to allow review and protect the Company's interest?

A. The provisions in the modified protective order that are used for the review of these CSAs have been used for many years and have been effective in preventing the inadvertent disclosure of these contracts. Under the terms of that modified protective order, there is a process for reviewing the documents, and "if a party reasonably believes that a limited, specific part of a document containing Highly Protected Information is necessary for inclusion in testimony in this proceeding or for use at hearing, the party may request a copy. In response to such a request, PacifiCorp will prepare a copy of the required portion of the document and provide it to that party."[6]

Q. Staff also noted that it would be helpful to understand the Commission's expectations for CSA negotiations, comparable to Sierra Club's request that the Commission establish "best practices" for future CSA negotiations.[7] Do you agree?

A. The Company agrees that Commission guidance would be helpful, but that guidance must be based on the real-world dynamics of CSA negotiations described in the Company's testimony. However, Sierra Club's representation of "best practices" for CSA negotiations are contrary to reasonable commercial and industry practices and should be rejected for the reasons discussed in the Company's reply and surrebuttal testimony.

Dave Johnston, Hunter, and Craig

Q. Does Staff continue to argue that the new CSAs for Dave Johnston and Craig are imprudent?

A. Yes. Staff originally argued that the CSAs were imprudent because the analysis used to inform the negotiations did not cover the entire contract term and did not adequately consider economic cycling. In response to the Company's reply testimony, Staff agrees that the Company's analysis covered the entire contract term but Staff still claims that the CSAs are imprudent because they did not consider economic cycling.[8]

---

[6] Order No. 21-086 at ¶15.
[7] Staff/1400, Anderson/8.
[8] Staff/1400, Anderson/9-10.

Q. Do you have any general response to Staff's recommendation related to the new CSAs?

A. Yes. The Company is concerned that Staff has taken its prospective recommendation discussed above and applied it retroactively to the CSAs that were negotiated and executed last year. As discussed in Mr. Staples' testimony, the Commission has never required the Company to model economic cycling like Staff recommends. Therefore, it is unreasonable to find a CSA per se imprudent for failure to account for modeling that has never been required before. The Company can agree to Staff's recommendation going forward, but applying it retroactively appears contrary to the Commission's long-standing prudence standard.

Q. Did Staff provide any specific evidence that the minimum take levels in the new Dave Johnston CSAs are excessive compared to the forecasted generation at the plant?

A. No. Staff did not provide any analysis indicating that the minimum take volumes in the Dave Johnston CSAs were unreasonable and Staff's recommendation failed to account for the facts and circumstances of the Dave Johnston plant and the market from which it purchases coal. In fact, Staff argued that the CSA was imprudent for not considering economic cycling, while conceding that the Dave Johnston plant is unlikely to be economically cycled.[9]

In the case of Dave Johnston, it is also important to recall that the new CSAs represent a relatively small fraction of the overall coal supplied to the plant. Indeed, the new CSAs represents only [redacted] of the plant's expected generation for the

[9] Staff/1400, Anderson/11.

2022 test period. And for 2022, [redacted] of the plant's expected generation is not under contract, i.e., the open position at the plant is larger than the new CSAs. This means that the Company could reduce generation at the plant by [redacted] and remain above the minimum take levels reflected in all the CSAs that supply the plant.

Q. Turning to the new Craig CSA, did Staff present any factual evidence that modeling economic cycling would have produced materially different generation forecasts for the plant?

A. No. Staff testified that the minimum take level for Craig [redacted][10] However, Staff claims that PacifiCorp did not consider economic cycling and therefore the CSA is per se imprudent. As discussed by Mr. Staples, had PacifiCorp modeled economic cycling, it would not have materially changed the generation forecast for Craig.

Q. Did Staff's recommendation account for the flexibility that the Company has under the Craig CSA?

A. No. As described in my reply testimony,[11] the new CSA represents approximately [redacted] of the forecasted generation at the plant, which means that there is a great deal of head room to decrease generation before hitting the minimum take level. But my testimony also explained that because the Trapper Mine is co-owned by PacifiCorp, the Craig CSA has a great deal of flexibility that can allow the Company to decrease the minimum take level if needed, based upon mutual agreement of the mine owners. This flexibility largely mitigates risks surrounding the Craig CSA's

---

[10] Staff/1400, Anderson/10.
[11] PAC/600, Ralston/15-17

minimum take level and is entirely ignored by Staff in its testimony. Application of Staff's rigid black-or-white prudence standard without regard for the totality of the circumstances surrounding the CSA is entirely unreasonable.

Q. Did Staff present any evidence that the Company can economically cycle the Craig plant given that PacifiCorp is only a co-owner of the plant and is not the operator?

A. No. Staff testifies that "PacifiCorp's argument that joint ownership at Craig precludes the ability to cycle the plant for economic reasons is unconvincing" because the Company "has not shown that it took any steps to evaluate economic cycling at Craig, or to discuss the possibility with co-owners."[12] However, Staff has continuously ignored the fact that each owner has different economic needs and load obligations, and coordinating economic cycling is not practical on a regular basis.

Q. Turning to the new Hunter CSAs, has Staff proposed a new adjustment?

A. Yes. Staff previously testified that the generation forecast analysis used for the new Hunter CSAs was "robust" and Staff agreed that the analysis allowed the Hunter units to economically cycle.[13] Staff now argues that the Hunter CSAs are imprudent because the "minimum take levels in PacifiCorp's coal contracts cannot be deemed prudent due to the Company's lack of analysis to assess whether economic cycling at any of its coal plants can reduce costs for ratepayers while maintaining reliability and other system requirements."[14] Staff's flip-flopping demonstrates the fundamental

[12] Staff/1400, Anderson/10.
[13] Staff/900, Anderson/16.
[14] Staff/1400, Anderson/11.

unfairness of Staff's recommendation to apply its newly articulated prudence standard to CSAs that were executed last year.

Q. Did Staff provide any evidence specific to the new Hunter CSAs to suggest that the minimum take levels are excessive?

A. No.

Huntington

Q. Has Staff modified its position on the Huntington CSA?

A. Yes. Staff no longer believes that the CSA is imprudent.[15] But Staff agrees with CUB's recommendation that the Company "conduct analysis to determine whether contract provisions in the CSA result in uneconomic dispatch of the plant, and if yes, whether that uneconomic dispatch is related to environmental laws and regulations."[16]

Q. How do you respond to Staff's new recommendation?

A. The Company agrees that it has an obligation to prudently manage the CSA, including determining whether there are reasonable grounds to invoke the termination provision in the agreement. But the Company does not agree that additional analysis or reporting is required at this time.

The Company regularly assesses the economics of the plant. If it becomes apparent that the plant is consistently unable to economically accept delivery of the minimum volumes, then the Company will then proceed to determine whether the consistent inability to economically accept coal deliveries at the plant is the result of an environmental regulation(s), *i.e.*, whether the plant would be economic but for the

[15] Staff/1400, Anderson/12.
[16] Staff/1400, Anderson/15.

environmental regulation(s).

Currently, even if the plant were to require alternate dispatch in order to reach the minimum take level, there is no evidence that the alternate dispatch is caused by environmental regulations. The examples cited by CUB, which are primarily state renewable generation mandates,[17] are too attenuated to justify invoking the termination provision in the CSA. No party has identified, and the Company is unaware of, any existing environmental regulation that is sufficiently tied to the Huntington plant to allow the invocation of the CSA's termination provision. It is unclear what additional analysis Staff envisions, but from the Company's perspective it has already conducted the analysis that Staff requested and concluded that there is no reasonable basis to terminate the CSA.

Q. Will the Company continue to monitor the plant to determine if there is a basis to terminate the CSA?

A. Absolutely. The Company is always committed to prudently managing all its contracts. The Company's interests are firmly aligned with customers and the Company has no incentive to continue to burn coal at Huntington if it is uneconomic. As market conditions and the regulatory environment change, the Company will continue to monitor Huntington to ensure that the Company reasonably exercises its ability to terminate the contract if doing so is prudent. The Company's annual TAM filings provide a reasonable forum for the Commission and stakeholders to assess the economics of the plant to ensure that the Company continues to prudently manage its obligations under the CSA.

[17] *See, e.g.*, CUB/200, Jenks/19.

Q. Staff also recommends that if the Company concludes that it can terminate the CSA, it perform a study to "consider opportunities for gas conversion, economic cycling, and early retirement of Huntington" and include the study as part of the 2021 IRP.[18] Is this reasonable?

A. No. Assuming for purposes of this response that the Company can terminate the CSA (which it cannot), the study that Staff recommends cannot be included in the 2021 IRP, which is due to be filed on September 1, 2021. If the Company determines at some point in the future that the Huntington CSA can be terminated, it will undertake the type of study Staff recommends and the Company agrees that study should occur as part of the IRP.

Q. Staff also recommends that, "the Company should seek provisions in future coal contracts that allow for contract termination if a plant becomes substantially uneconomic for reasons unrelated to environmental regulation."[19] How do you respond to this recommendation?

A. The Company agrees that broad CSA termination rights are beneficial but cautions that it cannot unilaterally impose those provision on CSA counterparties. Indeed, it is unlikely that a counterparty would agree to a provision that allows termination of the CSA if burning coal is uneconomic for any reason.

Moreover, the inclusion of the termination provision in the Huntington CSA was particularly important because it was a long-term agreement. The Company's practice of limiting the terms of new CSAs is designed, in part, to mitigate the same types of risk as the Huntington CSA's termination provision.

---

[18] Staff/1400, Anderson/15.
[19] Staff/1400, Anderson/16.

III. RESPONSE TO CUB

Huntington

Q. Does the Company agree with CUB's recommendation related to the Huntington CSA?

A. Yes. CUB "is asking that the Company prudently manage the termination clause."[20] The Company agrees with CUB that, "Today, the risks associated with contract termination may not be worth the value of such termination. But that may change."[21] The Company generally agrees with this testimony.

Q. CUB also testifies that there may be a basis for terminating the Huntington CSA because the increase in renewable resource generation has depressed wholesale market prices, thereby making it uneconomic to continue to burn coal at the levels included in the Huntington CSA.[22] How do you respond to this argument?

A. The Company disagrees that the growth in renewable generation is sufficient to justify PacifiCorp exercising the termination clause in the CSA. As CUB currently points out, exercising the clause is a serious matter with potentially significant consequences. In order to trigger the termination clause, PacifiCorp must be confident that doing so fits squarely within the termination rights included in the CSA. Increased renewable generation, on its own, is unlikely to meet the requirements for terminating the CSA because the increased generation must result directly from an environmental regulation(s). While there are certainly states that are increasing their renewable portfolio requirements, it is difficult to determine—with

[20] CUB/200, Jenks/21.
[21] CUB/200, Jenks/21.
[22] CUB/200, Jenks/18-19.

the certainty required to exercise the termination clause—that current wholesale market conditions have been caused by environmental regulations mandating increased renewable investments and that those increased renewable investments would not have occurred but for the state mandates. As noted above, PacifiCorp will continue to monitor and assess the market and regulatory environment and if it becomes reasonable to seek termination of the CSA the Company will do so.

IV. RESPONSE TO AWEC

Q. AWEC continues to recommend an adjustment to the material and supply expense for BCC based on its analysis of the historical variances between forecasted and actual material and supply expenses.[23] Do you agree with AWEC's recommendation?

A. No. As described in my reply testimony, the Company has historically forecast BCC costs accurately and it is unreasonable to select a single cost element in isolation (as AWEC has done) without considering offsetting factors.

Q. AWEC claims that PacifiCorp "did not dispute that the BCC material and supplies expenses had been grossly overstated."[24] Is this a fair characterization of your testimony?

A. No. In fact, the Company's testimony stated that Mr. Mullins' analysis purporting to show that the materials and supply expense was overstated was inaccurate, misleading, and inappropriate.

[23] AWEC/200, Mullins/20-23.
[24] AWEC/200, Mullins/21.

Q. AWEC also claims that PacifiCorp "acknowledged that it has historically overstated the cost per ton of coal from the BCC."[25] Is that a fair characterization of your testimony?

A. No. In fact, my testimony explained that from 2016 to 2020, the Company's forecasted BCC costs in the TAM filings were only [redacted] lower than BCC's delivered costs on a dollars per MMBtu basis.[26] My testimony also explained that when considering the total Jim Bridger plant, from 2016 to 2020, the received fuel costs on a dollars per MMBtu basis were [redacted] higher than the TAM estimate.[27] Each of these figures demonstrates that the Company's overall cost estimates are reasonable and that the variance between estimated and delivered coal cost is driven primarily by changes in delivered volumes, not an inability to forecast costs.

Q. Did AWEC dispute any of this analysis?

A. No. AWEC ignored it.

Q. AWEC also claims that its adjustment did not ignore offsetting factors.[28] Do you agree?

A. No. In my reply testimony, I pointed out that while forecasted materials and supplies line items may have been overestimated, other line items were consistently under-estimated, meaning that the overall estimate of BCC costs was reasonable, as demonstrated by the comparison discussed above. Although AWEC claims to have considered offsetting factors, there is no evidence that it did so. For example, my testimony pointed out that the actual costs for outside services were higher than

---

[25] AWEC/200, Mullins/21.
[26] PAC/600, Ralston/32.
[27] PAC/600, Ralston/32.
[28] AWEC/200, Mullins/21.

estimated by nearly the same amount as materials and supplies were lower—meaning that AWEC's proposed adjustment would be substantially offset if AWEC had actually considered offsetting factors. AWEC did not address this fact anywhere in its analysis or testimony. Accounting for the under-forecast of outside services—using the same framework and rationale as AWEC's materials and supplies adjustment—reduces AWEC's adjustment to just $[redacted]. When my testimony described AWEC's adjustment as "cherry picking," it was because AWEC's adjustment examined a single cost item in isolation without accounting for offsetting factors.

Q. AWEC claims that the overestimated materials and supplies expense is the primary driver of the fact that the Company's estimated coal costs have exceeded actuals.[29] Do you agree?

A. No. As discussed above, the primary driver is the variance in delivered volumes. When costs are examined on a dollars-per-MMBtu basis, the estimated and actual BCC coals costs are within [redacted].

Q. AWEC claims that "PacifiCorp did not attempt to explain why its materials and supplies expenses were so misstated relative to its forecast."[30] Is this true?

A. No. My testimony explained that the BCC materials and supplies costs were incurred both to mine coal and perform reclamation activities.[31] Reclamation activities were much higher than anticipated from 2018 to 2020. AWEC's analysis, however, applied all the materials and supplies expenses to the coal production, which made it

[29] AWEC/200, Mullins/22.
[30] AWEC/200, Mullins/22.
[31] PAC/600, Ralston/30.

appear that the amounts were consistently over-estimated. As discussed above, when BCC costs are examined holistically and offsetting factors are considered, they are very accurate.

Q. In the alternative to AWEC's primary recommendation, Mr. Mullins recommends that the Commission apply an [redacted] forecast error to BCC coal costs.[32] Is this a reasonable adjustment?

A. No. The [redacted] forecast error AWEC cites primarily reflects variances between estimated and actual delivered coal volumes, not the estimated coal costs. As discussed above, when comparing estimated and actual BCC costs accounting for volume variances shows that the Company's estimated costs have been very accurate.

Q. Although AWEC made adjustments to their material and supply calculation based on information provided by PacifiCorp, do you agree with AWEC's revised calculation?

A. No. The cost-plus return royalty valuation applies to tons produced from federal and state coal leases, not private coal leases. AWEC did not remove coal extracted from private lease areas in the royalty calculation and overstated the adjustment by $[redacted]

[32] AWEC/200, Mullins/23.

V. RESPONSE TO SIERRA CLUB

Coal Contract Terms

Q. Sierra Club recommends that a CSA with a minimum take level above 50 percent of the total projected volume should be subject to additional scrutiny.[33] Is this a reasonable recommendation?

A. No. First, it is unclear what is meant when Sierra Club recommends additional scrutiny. To the extent Sierra Club is recommending a heightened prudence standard for CSAs, such a recommendation is unreasonable and unnecessary. The Commission's existing prudence standard is sufficient for reviewing CSAs, just as it is sufficient to reviewing all other Company investments.

Second, as discussed by Mr. Schwartz, Sierra Club's 50 percent threshold is unprecedented. Mr. Schwartz's expert testimony explained that he has never encountered a coal buyer willing to have as little as 50 percent of its projected burn under contract for the upcoming year and that it would be highly risky for a utility to have so little coal purchased under contract for the upcoming year.[34] Sierra Club has failed to produce any relevant evidence supporting this recommendation, as discussed in more detail by Mr. Schwartz.

Q. Sierra Club also recommends that minimum take penalties should not be automatically passed through to customers.[35] Please respond.

A. PacifiCorp has never maintained that minimum take penalties should automatically be passed through to customers. The Company agrees that it has an obligation to

[33] Sierra Club/200, Burgess/26-27.
[34] PAC/500, Schwartz/30.
[35] Sierra Club/200, Burgess/27.

prudently manage its contracts and if a minimum take penalty is imposed because of PacifiCorp's imprudence, then customers should not have to pay the penalty. But if a CSA has been found prudent and the Company reasonably managed the CSA, then it is reasonable for customers to bear the costs of minimum take penalties because those penalties would have been prudently incurred.

To the extent that Sierra Club argues that PacifiCorp's shareholders should automatically pay minimum take penalties, if they arise, that recommendation should be rejected. Absent a finding of imprudence (either in executing the CSA or managing it in later years), PacifiCorp's shareholders should not bear minimum take penalties.

Sierra Club also claims that PacifiCorp is not "subject to competitive pressures" when negotiating its CSAs. It is true that as a vertically integrated and regulated utility, PacifiCorp does not "compete" with merchant generators in the same manner as an organized market. But regulation by the Commission acts as a proxy for market competition. In that way, PacifiCorp can only recover its costs if they are prudently incurred, which is not a standard that applies to merchant generators operating in organized markets.

Q. Sierra Club suggests that PacifiCorp's minimum take levels are not accounting for "where trends are headed given the general headwinds for coal economics."[36] How do you respond?

A. PacifiCorp disagrees. The Company's generation forecasts used to negotiate CSAs account for current and expected market conditions over the entire life of the CSA.

[36] Sierra Club/200, Burgess/28-29.

PacifiCorp's overall CSA contracting practices have also reflected the uncertainty surrounding coal generation, for example, by limiting CSA terms. The Company's resource planning practices have also accounted for trends in coal generation and reflected lower overall coal generation and increased renewable generation, as described by Mr. Staples.[37] Mr. Staples also describes in his surrebuttal testimony how PacifiCorp has been pursuing a strategy that allows it to reduce coal consumption in actual operations.

Q. Sierra Club claims that PacifiCorp mischaracterized the recent decision by the California Public Utilities Commission (CPUC) in the Company's 2020 Energy Cost Adjustment Clause (ECAC) proceeding.[38] To ensure that the record is accurate, what arguments did Sierra Club raise in that case?

A. According to the CPUC's order,

> Sierra Club argues PacifiCorp has a coal oversupply problem, particularly at Bridger and Naughton coal plants, attributable to erroneous coal burn forecasts based on low dispatch prices and long-term coal supply contracts with minimum take requirements. The result, as argued by Sierra Club, is that PacifiCorp locks itself into a cycle of high coal supply purchases without meaningfully considering the alternatives.
>
> Sierra Club further argues PacifiCorp's coal oversupply problem reflects the following two issues: First, Sierra Club states PacifiCorp has failed to produce any evidence in this proceeding that the minimum take requirements in its coal contracts are just and reasonable. Without specific documentation justifying the generation requirements at each plant, including an analysis of alternative options considered for serving customer energy needs, Sierra Club argues the Commission has little opportunity to evaluate or question whether the coal generation projections are reasonable. Second, Sierra Club states PacifiCorp has failed to demonstrate its coal supply agreements produce reasonable fuel costs for its ratepayers. While there are multiple types of

[37] PAC/400, Staples/49.
[38] Sierra Club/200, Burgess/36.

> contract provisions that may increase PacifiCorp's flexibility in fuel procurements, Sierra Club argues there is no evidence PacifiCorp has ever invoked one of these provisions for the benefit of its customers.[39]

Based on these arguments made by Sierra Club, the CPUC concluded:

> Notwithstanding Sierra Club's broader arguments that PacifiCorp has a coal oversupply problem, **<u>we have not found evidence in this proceeding that any of PacifiCorp's specific, underlying coal supply agreements are imprudent</u>**.[40]

While it is true that the specific CSAs at issue in the 2020 ECAC are not at issue in this case, Sierra Club's general arguments in this case surrounding the prudence of minimum take provisions and the Company's coal generation forecasting are substantively the same arguments rejected by the CPUC.

Moreover, just like here, in the 2020 ECAC, Sierra Club recommended that the CPUC "establish a heightened standard of review for contracts that have a minimum tonnage amount set at greater than 50% of the forecasted generation for the plant(s) at issue."[41] The CPUC also rejected that recommendation.[42]

Jim Bridger

<u>BCC Fixed Costs</u>

Q. Sierra Club questions the quantity of fixed costs associated with BCC mine production. Why are the fixed costs for BCC particularly relevant to Sierra Club's recommendations?

A. Generally, fixed costs are those that do not vary with production volumes. In other words, the fixed costs will be incurred irrespective of production volumes. Because

[39] 2020 ECAC, D.20-12-004 at 21 (Dec. 7, 2020).
[40] 2020 ECAC, D.20-12-004 at 24.
[41] 2020 ECAC, D.20-12-004 at 22.
[42] 2020 ECAC, D.20-12-004 at 24.

fixed costs are incurred regardless of production volumes, the overall unit price of BCC coal tends to increase as production decreases because the fixed costs are spread over a smaller volume.

As explained in more detail below, much of Sierra Club's arguments related to the economics of BCC and the Jim Bridger plant are based on Sierra Club's misrepresentations of the level of fixed costs for BCC.

Q. In general, what other concerns do you have regarding Sierra Club's testimony?

A. A significant portion of Sierra Club's testimony[43] is associated with an average cost dispatch methodology that is contrary to industry practices and prudent business fundamentals. The derivation of net power costs using an average cost dispatch methodology has been demonstrated to result in higher customer costs. BCC can produce supplemental coal in the 2022 TAM filing without additional capital expenditures. This enables BCC to effectively utilize the existing production capacity in the mine which benefits customers. In PacifiCorp's 2020 ECAC filing in California, the CPUC rejected Sierra Club's average cost dispatch methodology and approved PacifiCorp's use of incremental dispatch costs for the Jim Bridger plant.[44] The fact that Sierra Club's testimony relies heavily on conclusions drawn from an average cost dispatch evaluation that increases customer costs results in a large portion of their testimony being not only inaccurate but irrelevant.

Q. Please describe how Sierra Club has misrepresented the level of fixed costs for BCC.

A. Sierra Club's direct testimony claimed that PacifiCorp could identify only

[43] Sierra Club/200, Burgess/5-6,12,20-25.
[44] PAC/600, Ralston/46

$[redacted] of fixed costs for BCC, out of total 2022 costs of $[redacted].[45] Sierra Club based this testimony on selected portions of the discovery response provided by PacifiCorp (Sierra Club data request 2.5).[46] The Company's reply testimony pointed out that Sierra Club materially misrepresented the Company's discovery response and therefore misrepresented the level of fixed costs at BCC.[47]

Q. Sierra Club disputes that it intentionally omitted fixed costs for BCC in 2022 because PacifiCorp was only able to provide a numerical estimate for $[redacted] in "wholly identifiable fixed costs."[48] Did PacifiCorp also provide additional figures for other fixed costs?

A. Yes. In the same data request response that Sierra Club cites, the Company stated that "the majority of labor costs (~$[redacted]) would be considered fixed because a core set of skills is required to enable the mine to respond to future potential coal demand increases and complete reclamation as required by federal and state regulations."[49] In other words, the discovery response indicated that BCC fixed costs are approximately $[redacted], or nearly 50 percent of the total BCC costs for 2022 and nearly twice the

[45] Sierra Club/100, Burgess/56.
[46] PacifiCorp's Response to Sierra Club Data Request 2.5, which is as attached to Mr. Burgess' written testimony as Sierra Club/112, Burgess/5-7.
[47] PAC/400, Staples/64-65.
[48] Sierra Club/200, Burgess/2 (quoting Sierra Club/112, Burgess/6)
[49] Sierra Club/112, Burgess/6 (PacifiCorp's Confidential Response to Sierra Club Data Request 2.5(c)). For ease of reference, the relevant text states: "Other fixed costs are embedded in labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs that are independent of coal production activities. These costs would be incurred to comply with Mine Safety Health Administration and Wyoming Department of Environmental Quality (DEQ) requirements and to maintain and protect the mine infrastructure and equipment. Additionally and from the prism of a one year test period such as the transition adjustment mechanism (TAM) filing, the majority of labor costs [Confidential Begins] [redacted]) [Confidential Ends] would be considered fixed because a core set of skills is required to enable the mine to respond to future potential coal demand increases and complete reclamation as required by federal and state regulations. To identify all mine embedded fixed costs, a defined period would need to be established for the review. Then, Bridger Coal would need to complete an extensive review of each cost category. The relationship between fixed and variable costs change depending on the time period of the review."

amount Sierra Club claimed in its testimony. This means that even if PacifiCorp were to dramatically reduce production at the mine (as Sierra Club recommends) the cost savings would be far less than Sierra Club assumes because *at least* 50 percent of the estimated costs would be incurred regardless of volumes.

Q. Did Sierra Club explain why it ignored nearly half of the quantified fixed costs PacifiCorp identified in its response to Sierra Club data request 2.5?

A. Yes. Sierra Club claims that "because PacifiCorp was unable to provide any numerical estimate for the 'embedded' fixed costs . . . [Sierra Club] presumed the fixed cost component of these other items was *de minimus*."[50] This testimony cannot be squared with the fact that the discovery response specifically provided a numerical estimate for the labor portion of the "embedded" fixed costs and that estimate was $[redacted], which is hardly *de minimus*.

Q. Sierra Club also claims that PacifiCorp did not provide any evidence that there were significant fixed costs in excess of $[redacted].[51] Is this accurate?

A. No. As noted above, PacifiCorp's original discovery response identified at least [redacted] in fixed costs over and above the wholly identifiable fixed costs of $[redacted]. PacifiCorp then confirmed through a subsequent discovery response[52] that the fixed costs would be at least $[redacted] (consistent with its earlier discovery response and reply testimony). PacifiCorp also explained that there were additional fixed costs embedded within other cost elements, meaning that the quantified estimate of [redacted] was conservative and that actual fixed costs were higher.

---

[50] Sierra Club/200, Burgess/2.
[51] Sierra Club/200, Burgess/3.
[52] Sierra Club/201, Burgess/1.

Q. Sierra Club claims that PacifiCorp should have differentiated between fixed and variable costs by preparing two mine plans with different levels of operations.[53] Did PacifiCorp perform the analysis Sierra Club recommends?

A. Yes. The BCC delivered coal quantity and cost information included in the 2022 TAM can be summarized in PAC Confidential Table 1 below:[54]

[redacted]

Q. Can you please describe BCC base mine plan assumptions that were used to derive these figures?

A. Yes. In 2022, BCC was forecast to deliver [redacted] tons from the surface mine and [redacted] tons from the underground mine to the Jim Bridger plant for a total of [redacted] tons. The two draglines were assumed to each operate one 12-hour shift per day, seven days per week. BCC was forecast to complete [redacted] cubic yards of final reclamation work. The base operating price included all operating costs (labor/benefits, materials/supplies, equipment repairs, outside services, depreciation/depletion, royalties, production taxes/fees, coal inventory, final reclamation, other miscellaneous costs) incurred to deliver the forecast tonnage amount.

Q. Can you please describe BCC supplemental coal delivery assumptions?

A. Yes. The supplemental coal delivery amount was determined by subtracting BCC base and Black Butte contract MMBtu quantities from the forecasted Jim Bridger

[53] Sierra Club/200, Burgess/5-6.
[54] This information was extracted from my workpapers.

plant consumed MMBtu amount in the TAM filing. The supplemental price was calculated by comparing differences between two mine plans, as Sierra Club recommends. As noted above, the base mine plan assumed both draglines operated *one* 12-hour shift per day, seven days per week. The alternative mine plan assumed both draglines operated *two* 12-hour shifts per day, seven days per week. The supplemental price was determined by dividing the cost differential between the two mine plans by the MMBtu differential between the two mine plans. The calculated price of $[redacted] per MMBtu represents the price to produce and deliver each additional MMBtu within the evaluated mine plan range. This price is the supplemental, incremental or marginal cost.

Q. Sierra Club claims that PacifiCorp did not consider decreased production levels at BCC.[55] Is that accurate?

A. No. As discussed in more detail below, when developing the base mine plan, the Company considered a range of production levels, including decreased production. The [redacted] tons of supplemental coal delivered provides further evidence that the base mine plan volume was not set too high.

Q. Do you agree with Sierra Club's assertion that "certain items PacifiCorp identified such as materials/supplies and electricity are obviously a direct function of the volume of coal extracted and it is only logical to treat them as variable costs with no fixed component"?[56]

A. Absolutely not. PacifiCorp's response to Sierra Club's data request 2.5(c), stated:

> Other fixed costs are embedded in labor and benefits, materials/supplies, electricity, outside services and other

[55] Sierra Club/200, Burgess/6.
[56] Sierra Club/200, Burgess/2-3.

> miscellaneous costs that are independent of coal production activities. These costs would be incurred to comply with Mine Safety Health Administration and Wyoming Department of Environmental Quality (DEQ) requirements and to maintain and protect the mine infrastructure and equipment.

Sierra Club's witness, who has no relevant experience operating a mine, does not understand the mine's compliance obligations required to maintain a mining operation, such as keeping mining areas dewatered, maintaining haul roads, managing coal stockpiles, gathering data and preparing compliance reports, maintaining equipment, and using electricity to enable all of these activities, which must be completed regardless of production volumes. Furthermore, the mine would pay fixed electricity demand charges and would incur energy usage charges to energize facilities and maintain equipment.

Q. Sierra Club argues that the approximately $[redacted] in projected labor costs should not be characterized as fixed because these "costs might be substantially reduced prior to 2022 if a lower coal volume need was projected."[57] Can the Company substantially reduce labor costs for BCC in the 2022 TAM?

A. No. As detailed in the reply testimony of Mr. Schwartz, many of the costs PacifiCorp identifies as fixed must be performed at the same level regardless of the level of operations.[58] BCC must maintain a workforce of qualified and experienced coal miners to operate the mine according to the Company's approved mine plan. As Mr. Schwartz explains in his reply testimony, if PacifiCorp were to lay off a significant portion of BCC's workforce to reduce costs in the 2022 TAM, it would

---

[57] Sierra Club/200, Burgess/3.
[58] PAC/500, Schwartz/18-19.

not be able to conduct steady operations and use the coal inventory fluctuations to support the variability in coal burn.[59]

Sierra Club's witness, who has no experience in mining operations, believes that if PacifiCorp suddenly decided to reduce BCC volumes by one-half (which appears to be Sierra Club's recommendation using a flawed average cost methodology),[60] then PacifiCorp could lay off a substantial portion of its workforce for 2022 and then, if necessary to deliver increased volumes in 2023, simply rehire the same workforce for 2023. Actual operations do not work this way. The Company cannot retain its skilled workforce if there are wild swings in production requiring drastic changes to the workforce year to year. If PacifiCorp laid off a substantial portion of its labor force, as Sierra Club effectively recommends, it would not get them back if required volumes were to increase in subsequent years.

In addition, when mining activity is reduced because of lower production volumes, the Company has historically been able to efficiently shift labor to reclamation activities, which must occur regardless of production volumes. Adopting Sierra Club's approach to mining operations would seriously hinder the Company's ability to efficiently mine coal and undertake required reclamation, resulting in higher overall costs to customers.

[59] PAC/500, Schwartz/20.
[60] *See, e.g.*, Sierra Club/200, Burgess/10-11, 19.

Q. Sierra Club claims that, "It may be possible for PAC to significantly reduce the amount of fixed costs at BCC in 2022 if a lower production volume were pursued."[61] Is that a reasonable approach?

A. No. First, it is also important to keep in mind that Sierra Club's only basis for recommending a dramatic reduction in BCC production volumes is because of Sierra Club's highly unorthodox proposal to dispatch the plant using average, instead of incremental cost, which is discussed in more detail in Mr. Staples' testimony. Even if this approach were used, fixed costs do not vary depending on volumes and thus most costs would be incurred even if volumes were reduced. For example, as discussed above, the labor costs would remain largely the same because the workforce would be maintained to conduct steady operations, use coal inventory fluctuations to support variability in coal deliveries and perform available reclamation activities. The Company would also still incur costs to comply with applicable environmental regulations to maintain and protect the mine infrastructure and equipment. Costs such as depreciation, depletion, insurance/bonds, property tax and final reclamation contributions cannot be "significantly reduced."

Q. Sierra Club argues that its average cost model run's coal fuel expenditures of $[redacted] for Jim Bridger will be "more than sufficient" to cover remaining fixed costs of "scaled down BCC production and other obligations" at the plant.[62] Do you agree?

A. No. In addition to the fact that Mr. Burgess' analysis is based on an average dispatch methodology that is incorrect and increases customer costs, he failed to consider:

[61] Sierra Club/200, Burgess/6.
[62] Sierra Club/200, Burgess/23.

(1) management employee severance costs and union severance and benefit costs as required in the working agreement with the International Brotherhood of Electrical Workers triggered by his significant reduction in labor costs, (2) final reclamation contributions ($[redacted]) required to comply with federal and state legal obligations, (3) depreciation expenses incurred for capital investments between April 1, 2021 and December 31, 2022 ($[redacted]), (4) additional coal inventory and deferred longwall expenses incurred between April 1, 2021 and December 31, 2022 ($[redacted]), (5) embedded fixed costs in material and supply costs as discussed in response to Sierra Club 2.5, and (6) federal and state royalties associated with increased costs noted above. In summary, Mr. Burgess' analysis contains substantial flaws and should be rejected in its entirety.

Q As discussed above, Mr. Burgess reduced BCC labor and benefit costs in his flawed analysis by [redacted] in Confidential Table 3 and described those costs as "variable". Do you agree?

A. No. Changes in BCC mine plans and staffing levels need to be evaluated in multi-year evaluations such as PacifiCorp's IRP and not in a one-year filing like the TAM. A [redacted] reduction in labor and benefit costs would result in an approximate reduction of [redacted] employees. Not only would it be imprudent to incur costs to terminate and then later hire [redacted] employees in one year, it is highly unlikely the skills of those terminated employees could be replaced and would need to be developed over an extended period of time. Additional costs would be incurred to train new hires and offset the unfavorable impact of reduced productivity rates.

Q. In the corrected rebuttal testimony, Sierra Club states that "PacifiCorp did not identify any labor costs among those cost incurred prior to the 2022 TAM filing"[63] and concluded there were "no additional labor costs or any other costs associated with 2022 BCC production could be considered fixed at the time of the 2022 TAM filing." Is Sierra Club's conclusion accurate?

A. No. First, Sierra Club criticizes PacifiCorp for not referencing BCC's working agreement with the International Brotherhood of Boilermakers provided in response to Sierra Club Data Request 5.5(c) even though a copy of the agreement was provided in the response to Sierra Club Data Request 3.2. In fact, Mr. Burgess' very next sentence states "Based on my review, nothing in this agreement would prohibit PacifiCorp from reducing the mine's work force if the Company determined that lower production was in the best interest of ratepayers." Mr. Burgess' criticism appears to be unfounded and disingenuous. The fact that Mr. Burgess assumed a significant workforce reduction in Confidential Table 3 and failed to recognize that if this event occurred additional severance and benefit costs would be incurred after having reviewed the agreement is yet another indication of the flaws in his analysis. Second, as discussed further below, Sierra Club's distinction assumes that only costs incurred "at the time of the 2022 TAM filing" are fixed and ignores costs incurred from April 1, 2021 through December 31, 2022. This is simply not the case.

[63] Sierra Club/200, Burgess/4-5.

Q. Sierra Club claims that as of the filing date for the 2022 TAM, the Company has only incurred approximately $[redacted] of BCC costs.[64] Does that mean that the Company could have avoided all but that $[redacted] if it had changed mine plans when the TAM was filed?

A. No. Sierra Club again mischaracterizes a Company data request response and omits material qualifications provided by the Company. Sierra Club's testimony is based on incomplete data and a misrepresentation of the Company's response to Sierra Club Data Request 5.5(b).[65] In this data request response, the Company explained that costs included in the 2022 TAM that were incurred prior to April 1, 2021, were approximately $[redacted]. The Company also stated that the $[redacted] figure does not include *obligations* BCC has as of April 1, 2021, that are included in the TAM, such as costs for final reclamation, property taxes, mine compliance costs, and employee benefits, among others. There is no basis to assume that the Company could have avoided all but $[redacted] as of April 1, 2021. Again, Sierra Club selectively quoted a discovery response and omitted relevant information that contradicted its testimony.

Q. Sierra Club assumptions in its average cost run also require a [redacted] reduction in BCC production for 2022.[66] Is this possible considering operational constraints and reliability concerns?

A. No. As explained above, the average cost methodology has been shown to be flawed. Furthermore, BCC cannot operate at a [redacted] reduced capacity and still produce

[64] Sierra Club/200, Burgess/23.
[65] Sierra Club/201.
[66] Sierra Club/200, Burgess/24 n.39.

coal at the same price because of reduced economies of scale and inefficient use of mine equipment and workforce constraints.

Q. Sierra Club's average cost run also excluded any reclamation costs for BCC because it believes that PacifiCorp has "mischaracterized" this item as a fixed cost and "may also be inflating these costs for other reasons."[67] Should reclamation costs for BCC be included in the 2022 TAM?

A. Yes. PacifiCorp plans to shut down the underground mine at BCC estimated at the end of 2021. PacifiCorp must comply with state and federal environmental regulations addressing the decommissioning of coal mining facilities. Even Sierra Club's opening testimony admitted that "final reclamation costs are unavoidable."[68] Indeed, Sierra Club also believed that these costs may have been high because they were (1) partially based on coal yet to be mined and (2) may be high because the Company had not taken "proactive steps" in the past to collect reclamation funds in previous TAMs.[69] In response to these unsubstantiated allegations, PacifiCorp responded that (1) final reclamation costs are reviewed and recalculated annually as a part of BCC's budget process and (2) reiterated that the 2019 IRP concluded that the continued operation of BCC was in the public interest.[70] Instead of addressing the Company's response, Sierra Club chose to simply ignore reclamation costs that it agrees must be paid.

[67] Sierra Club/200, Burgess/25.
[68] Sierra Club/100, Burgess/57.
[69] Sierra Club/100, Burgess/57-58.
[70] PAC/600, Ralston/50-51.

Q. Sierra Club does offer an alternative proposal that results in an adjustment of [redacted] Company-wide or [redacted] Oregon-allocated, which it states includes the Company's full estimated reclamation costs.[71] Is this number reflective of reasonable Jim Bridger fueling costs?

A. No. Sierra Club's calculation is based on a flawed average cost dispatch methodology that is contrary to industry practices, prudent business fundamentals, and would increase customer costs.

Q. Sierra Club argues that the dispatch tier costs for Black Butte are excessively low because the Black Butte CSA will be a new contract including a minimum take provision.[72] Is the dispatch tier price of Black Butte coal in the 2022 TAM in line with the historical price of Black Butte coal in previous TAM proceedings?

A. The dispatch price at the Jim Bridger plant is based on Bridger Coal incremental pricing, not pricing from Black Butte Coal Company as suggested by Sierra Club.

<u>BCC Mine Plans</u>

Q. Sierra Club testifies that PacifiCorp has not prepared an updated BCC mine plan since 2019.[73] Is this correct?

A. No. The Company prepares an updated BCC mine plan every year as part of its annual budgeting process. As noted earlier in my testimony, several mine plans were developed to ensure an adequate amount of coal would be available to meet the

[71] Sierra Club/200, Burgess/25.
[72] Sierra Club/200, Burgess/36-37.
[73] Sierra Club/200, Burgess/7.

plant's forecast consumed quantity and inform BCC's marginal cost in the TAM filing.

Q. Sierra Club claims that the Company did not evaluate BCC mine plans in its 2021 and 2022 TAM that examined reduced production levels.[74] Is that true?

A. No. The Company's annual BCC mine plans examine a range of different volume scenarios to determine the optimal plan for the relevant planning period (for example, the most recent mine plan which was finalized in fall 2020). Contrary to Sierra Club's claim, the Company regularly assesses different mine plans for BCC that examine a range of different production levels.

Q. Sierra Club claims that most other fuel suppliers have kept their costs "substantially lower than BCC" and suggests that this is because BCC is "essentially immune from any competitive market pressures that would otherwise serve as a mechanism to contain costs."[75] How do you respond?

A. I disagree. Sierra Club's claims that there are no pressures that serve as a mechanism to contain BCC costs completely ignores the regulatory process—including the TAM—where BCC costs are often examined in detail on an annual basis. As I described in my reply testimony, annual BCC costs have been a significant issue in the 2014, 2017, 2018, 2019, and 2020 TAMs and the Commission has consistently concluded that BCC costs are reasonable.[76] In addition, BCC costs are also examined in general rate cases.

Second, Sierra Club implies BCC is immune from competition because it is an

[74] Sierra Club/200, Burgess/7.
[75] Sierra Club/200, Burgess/8.
[76] PAC/600, Ralston/42-44.

affiliate and ignores the fact that there is not a viable "competitive market" for coal that can be delivered to the Jim Bridger plant at a lower cost than BCC. Moreover, the Commission has on several occasions affirmed the reasonableness of the Company's continued reliance on BCC coal over potential market alternatives:

- In the 2017 TAM, the Commission found that the Company was prudent for "not accelerating conversion to Powder River Basin (PRB) coal" in 2013 as an alternative to BCC.[77] The Commission found that PacifiCorp "demonstrated that it considered market alternatives to BCC coal before, during, and after 2013 in its various approaches to long-term planning for the plant, but consistently found the cost of conversion to PRB coal too costly."[78]
- In the 2017 TAM, the Commission also rejected a recommendation to "substitute a market rate [based on PRB coal] for BCC pricing in 2017."[79]
- In the 2014 TAM, the Commission rejected an adjustment that would have repriced BCC coal using Black Butte pricing as a market alternative. The Commission found that PacifiCorp's approach to fuel supply was reasonable and that the "Commission has historically approached the company's affiliate transactions with a cost-based approach, and that in the case of BCC coal, there is no possibility of utility-affiliate cross-subsidization."[80]

Q. Has Sierra Club presented any evidence that there is a lower cost alternative coal supply available for the Jim Bridger plant?

A. No. Comparing BCC costs to coal costs for other plants, who source their coal from

[77] Order No. 16-482 at 6-7.
[78] *Id.*
[79] *Id.* at 8.
[80] Order No. 13-387 at 6.

other markets, is not a reasonable methodology for evaluating the reasonableness of BCC costs, as the Commission has repeatedly concluded in prior TAMs.

Q. Sierra Club continues to argue that because "the TAM is evaluated in the year *before the year of the mine plan*" many of the costs associated with mine costs are not fixed and may still be avoidable.[81] Do you agree?

A. No. The Company creates mine plans and fueling strategies for its coal-generated facilities on longer time scales than the one-year TAM forecast. Therefore, the costs PacifiCorp provided to Sierra Club as fixed costs accurately represent unavoidable fixed costs on the one-year time scale of the TAM. Sierra Club's testimony here demonstrates how little it seems to understand about the operational realities of running a mine. In this way, most of the issues raised by Sierra Club are better addressed in the Company's IRP where longer term resource planning is addressed.

<u>BCC Base and Supplemental Coal Pricing</u>

Q. Sierra Club states that "using an alternative resource higher in cost than the BCC supplemental price but lower than the BCC base price can lead to lower overall costs"[82] and provided an illustrative example supporting their statement. Do you agree with Sierra Club's calculations?

A. No. Sierra Club assumes that BCC could reduce its production by 50 percent without any change in the per-MMBtu price. But because of the fixed costs (discussed above), if production decreased by 50 percent, the price per MMBtu would increase significantly as the fixed costs are spread over lower volumes. By adjusting only the

[81] Sierra Club/200, Burgess/35 (emphasis in original).
[82] Sierra Club/200, Burgess/18-19.

volumes but not the price, Sierra Club's example is inaccurate and does not demonstrate that reducing BCC production is lower cost.

Q. Can you explain why Sierra Club's example is inaccurate?

A. Yes. For reference, the information contained in Sierra Club's Confidential Table 2 is summarized below (line-item cost information has been added by PAC for reference purposes):

[redacted]

Sierra Club's "50% BCC Replacement Scenario" reduces BCC's base quantity from [redacted] MMBtus to [redacted] MMBtus. However, Sierra Club fails to recognize that a portion of costs included in the base rate of $[redacted]/MMBtu are fixed costs and will not decrease with a reduction in MMBtus produced at BCC. Sierra Club multiplied the reduced BCC quantity ([redacted] MMBtus) by the original base rate and projected an overall cost reduction when in fact this methodology would result in higher costs paid by customers.

Q. Can you correct the errors in Sierra Club's base price calculation?

A. Yes. The base dollar amount of $[redacted]/MMBtu includes both fixed and variable costs to deliver the [redacted] MMBtus. To correct Sierra Club's calculation, I multiplied BCC's base MMBtu quantity [redacted] MMBtu) by BCC's supplemental/marginal price ($[redacted]/MMBtu) and then subtracted that amount from BCC's base dollar total ($[redacted]) in the TAM filing. The balance

($[redacted]) represents an estimate of the base/fixed amount that would not change with a reduction in MMBtu's delivered. I then multiplied the adjusted MMBtu quantity ([redacted]) by the supplemental/marginal price ($[redacted]/MMBtu) and added that amount ($[redacted]) to the estimated based/fixed dollar amount for a total of $[redacted]. The corrected, indicative BCC base price per MMBtu is $[redacted] and is calculated by dividing the revised dollar total ($[redacted]) by the adjusted BCC base MMBtu quantity ([redacted]).

Q. Can you quantify the cost increase customers would pay if Sierra Club's methodology was implemented?

A. Yes. PAC Confidential Table 3 has been adjusted to reflect BCC's corrected base price estimate:

[redacted]

In summary, Sierra Club's calculation estimating a cost reduction of $[redacted] is incorrect because Mr. Burgess failed to recognize that fixed costs won't change with a reduction in MMBtu's delivered at BCC. The correct cost per MMBtu for BCC's reduced base quantity is $[redacted] not the $[redacted] cost per MMBtu assumed by Mr. Burgess. As identified above, customer costs are projected to increase by $[redacted] not decrease by $[redacted] using Mr. Burgess' methodology.

Q. Do you have other concerns with Sierra Club's calculations contained in Sierra Club's Confidential Table 2?

A. Yes. Sierra Club assumed an additional [redacted] MMBtus could be sourced at "the weighted average of all of PacifiCorp's coal units."[83] This simplistic assumption completely ignores transmission constraints, planned unit outages, contractual obligations, transportation logistics, and realities of fuel supply. But, again, even using this assumption, Sierra Club's recommendation would increase customer costs.

Q. Sierra Club states that "Although ratepayers benefit from subsequent consumption of lower priced coal (supplemental quantity), this happens only after the Company has consumed a significant amount of the base quantity at an economic loss".[84] Do you agree with Sierra Club's assessment?

A. No. It would be impossible to enjoy the benefits of lower priced supplemental coal without first having to incur costs to permit and develop a mine, purchase equipment, hire employees, pay taxes and reclaim the disturbed property. Sierra Club's apparent refusal to acknowledge that fixed costs[85] represent a significant portion of BCC's overall costs is implausible. In PacifiCorp's response to Sierra Club Data Request 2.5(c), the Company identified "wholly identifiable" fixed costs of $[redacted] and stated the majority of labor costs (~$[redacted]) would also be considered fixed. The combined fixed cost amount specified in the response estimated $[redacted] and aligns closely with the base/fixed amount identified in PAC Confidential Table 1 above.

[83] Sierra Club/200, Burgess 19.
[84] Sierra Club/200, Burgess 14-15.
[85] *See, e.g.*, Sierra Club/200, Burgess 2-6.

Q. Sierra Club also claims that the Company can sign CSAs knowing that they will be selling at a loss because of the TAM and the Power Cost Adjustment Mechanism, "which disconnect cost recovery from market competition."[86] Do you agree?

A. No. Sierra Club's argument has no basis in the realities of PacifiCorp's system or the Commission's prudence review standard. CSAs are reviewed by the Commission to ensure that the Company, knowing what it knows at the time it enters the contract, made a prudent business decision.[87] If PacifiCorp knew at the time that it would be selling power at a loss under a CSA, the Commission would disallow those costs and not include the expenses in future TAMs. As explained extensively in prior TAMs and the record in this case, including Mr. Schwartz's expert testimony, minimum take provisions are necessary to avoid relying on the illiquid spot market for coal at its facilities, which would expose customers to the potential for significantly higher coal costs pose serious threats to reliable operations.[88]

<u>BCC Reporting</u>

Q. Sierra Club continues to recommend that TAM filings include reports on BCC coal costs and claims that it is "surprised that PacifiCorp would object to additional transparency[.]"[89] How do you respond to this claim?

A. The Company does not object to transparency into its operations—as discussed above, BCC costs and operations have been heavily litigated in prior TAMs and the

[86] Sierra Club/200, Burgess/14.
[87] 2017 TAM, Order No. 16-482 at 6.
[88] *See, e.g.*, 2017 TAM, Order No. 16-482 at 9 ("[W]ithout entering into supply agreements with [minimum take] provisions, [PacifiCorp] would have to reply on the spot market with the attendant supply and price risk.").
[89] Sierra Club/200, Burgess/9.

mine and its operations have been regularly scrutinized by Staff, Parties (including Sierra Club), and the Commission. Sierra Club's recommendation for additional reporting, however, is excessive and is not well suited for the TAM and are better addressed in PacifiCorp's long-term fuel plans and IRP processes.

Q. Why is Sierra Club's reporting requirement outside the scope of the TAM?

A. Sierra Club requested that PacifiCorp "include a report on the steps it has taken to reduce ratepayer costs associated with the BCC mine and replace this generation with lower cost sources."[90] The evaluation of potential resource alternatives to the Jim Bridger plant is conducted in the Company's IRPs, not the TAM. Filing annual reports in the TAM addressing an issue that is outside the scope of the TAM makes little sense. Similarly, the Company already reports changes to BCC costs in each TAM filing as part of its coal cost update. Imposing additional and likely burdensome reporting requirements is unnecessary.

<u>**BCC Volume**</u>

Q. Sierra Club argues that the Company can substantially reduce the volume of coal from BCC if it simply generated less at the Bridger plant.[91] Is Sierra Club's recommendation reasonable?

A. No. Sierra Club claims that the Company can reduce generation at the plant by approximately [redacted] based on Sierra Club's recommendation to dispatch using average, rather than incremental price. As discussed by Mr. Staples, Sierra Club's average price dispatch recommendation is entirely unreasonable and contrary to well established economic principles and industry practices.

---

[90] Sierra Club/100, Burgess/74.
[91] Sierra Club/200, Burgess/10-11.

Q. Sierra Club also claims that the Company may not have to enter into a new Black Butte CSA if it used average price dispatch.[92] Is that a reasonable recommendation?

A. No. Again, Sierra Club's only basis for claiming that there is no need for Black Butte coal is its reliance on a flawed average cost that represents a radical change to the Company's and industry's long-standing dispatch methodology.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[92] Sierra Club/200, Burgess/10.

Docket No. UE 390
Exhibit PAC/1300
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Seth Schwartz

August 2021

TABLE OF CONTENTS

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

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the rebuttal testimony of Mr. Ed Burgess, filed on behalf of Sierra Club.

Q. Please summarize your testimony.

A. My testimony establishes the following points:

- The only evidence cited by Mr. Burgess in support of his opinion that a coal contract minimum take level of "50 percent of the total projected volume was a reasonable level that would reduce risk to customers"[1] was an article in the trade press. In fact, this article provides no support for the opinion of Mr. Burgess and supports my opinion that utilities do not enter a year with contracted volume anywhere near as low as 50 percent of expected burn.
- The recommendation by Mr. Burgess that PacifiCorp should accept the financial risk of any penalties associated with minimum take requirements in coal contracts is contrary to standard regulatory practices and will not promote behavior that will benefit customers.

[1] Sierra Club/200, Burgess/26.

II. PRUDENT MINIMUM COAL CONTRACT COMMITMENTS IN THE ELECTRIC UTILITY INDUSTRY

Q. Mr. Burgess has recommended that the Public Utility Commission of Oregon (Commission) "should conduct additional scrutiny for any CSAs that include a minimum take quantity that is over 50 percent of the forecasted need."[2] Has Mr. Burgess provided any support for his selection of this 50 percent threshold?

A. None whatsoever. In response to PacifiCorp data request 1.7, Mr. Burgess simply stated that his "recommendation is based on his expert opinion and professional judgment that minimum take requirements exceeding a certain percentage of projected coal fuel burn are imprudent." He provides no experience or analysis to show that a maximum coal contract commitment of 50 percent of expected burn is consistent with prudent utility practices.

Q. Why do you reference "prudent utility practices"?

A. That is the standard by which the Commission should consider the recovery of the Company's fuel costs in the Transition Adjustment Mechanism. Any judgement of prudency must be based upon the standard of the actions of a reasonable Company based upon the information and conditions known at the time of the decision. One way to evaluate the reasonableness of the Company's actions is the standards used by the utility industry at the time of the purchasing decisions.

Q. What are the standards used by the utility industry for coal contract commitments entering a contract year?

A. While circumstances vary for each utility, based upon their own situation and the coal markets that comprise their economic supply options, in my experience utilities

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

ensure that they have the ability to supply 80 – 100 percent of their expected requirements under contract entering a new year. Utilities seek some contract volume flexibility, if available (suppliers seek to avoid any volume flexibility, if possible), and are likely to have minimum take requirements of 70 – 90 percent of expected coal requirements entering a new year. In my experience of 40 years consulting for the electric utility industry, I have never encountered any utility (or merchant power generator) that is willing to have as little as 50 percent of its expected requirements for the current year under contract commitments.

Q. Why is it standard utility practice to have 80 – 100 percent of expected coal requirements under contract for the current year?

A. As I stated in my reply testimony, coal markets are fairly illiquid, and coal must be contracted in advance of physical delivery. There is no true "spot" market for coal (as there is for natural gas or electric power) where it can be purchased for immediate delivery or even delivery the next day. If a utility has less than at least 80 percent of its coal under contract, it faces a significant risk of not being able to purchase enough coal promptly to maintain adequate supply and may have to curtail generation. Such an event could be a high cost to its customers or even cause a shortage in power supply. The impact to customers of running short of coal would be much greater than the impact of contracting for coal that turned out to be in excess of actual requirements if coal burn were lower than expected.

Q. Mr. Burgess testified that you have "a long history working for the coal industry" but "may be less familiar with some of the more recent trends that point towards increasing shares of coal being delivered through spot contracts."[3] How do you respond?

A. I and my company have decades of work in the electric power industry (not just the "coal industry"), analyzing and advising interested parties in prudent utility fuel procurement practices and procedures. We have performed such work for electric utilities, merchant power generators, electric utility commissions, and intervenors in utility fuel clause cases. We have audited electric utility fuel procurement practices and procedures for utility management as well as for utility commissions. We have drafted fuel procurement plans for numerous electric utilities and have advised them in implementing such plans. We have acted as fuel procurement agents on behalf of large coal-fired power generators. Our work spans almost 40 years and includes numerous projects in the current year. I am fully aware of "recent trends" in fuel procurement practices with regard to "coal being delivered through spot contracts or shorter-term lengths".[4]

Q. Mr. Burgess cited "a recent article published by S&P Global Market Intelligence" as an example of "recent trends" that have informed his testimony. Does that article support his opinions?

A. No. Mr. Burgess confused the statement in that article that "in 2020, about 48.1% of coal deliveries arrived at U.S. power plants on spot contracts or on contracts with less

[3] Sierra Club/200, Burgess/28.
[4] Sierra Club/200, Burgess/28.

than a year remaining on the term"[5] as supporting his opinion that utilities do not need to purchase more than 50 percent of coal under contract.

Q. Please explain why this article does not support Mr. Burgess' opinion.

A. Even though 48.1 percent sounds a lot like 50 percent, the S&P article combines "spot contract" deliveries with "contracts with less than a year remaining on the term". Coal deliveries under contracts with less than one year remaining are **contract** purchases, not **spot** purchases.

Q. But if the contracts have less than one year remaining, aren't they short-term purchases?

A. No. They may be deliveries under multi-year contracts that happen to be expiring in the year being analyzed. That does not mean these were short-term coal purchases.

Q. Did you perform an analysis of the data underlying the S&P Global article?

A. Yes. I spoke to the reporter who wrote the article and S&P provided me with the data underlying the charts in the article.

Q. What is the source of the data cited in the S&P article?

A. The data come from a data base known as the Energy Information Administration (EIA) Form 923, which can be obtained from EIA's web site at https://www.eia.gov/electricity/data/eia923/. I use this data regularly in my normal course of business.

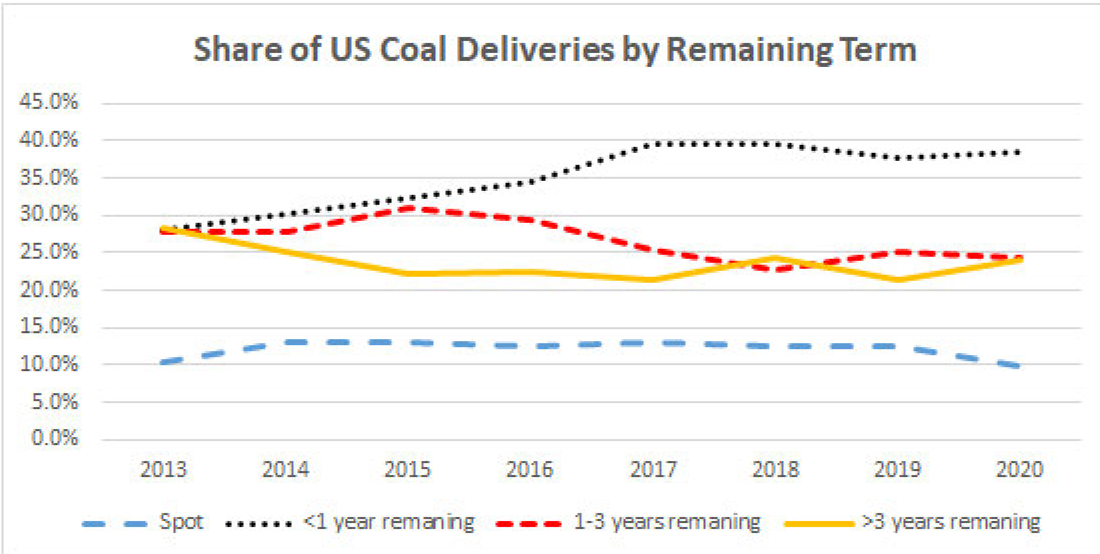
Q. Have you prepared an analysis of the share of coal deliveries under "spot" contracts?

A. Yes.

[5] Sierra Club/200, Burgess/28.

Q. What does your analysis show?

A. The percentage of coal delivered under "spot" contracts (defined on the EIA Form 923 as contracts with term less than 12 months) has been steady since 2013 at 9.7 percent - 13.1 percent of total purchases.[6]



Q. Do the "more recent trends" point towards an increasing share of coal purchased by utilities under "spot" contracts?

A. No. If anything, the share of coal delivered under spot contracts declined in 2020, although I expect it will return to the level of 12 percent – 13 percent that has prevailed since 2014.

Q. What do you conclude from your analysis of the article relied upon by Mr. Burgess?

A. U.S. electric power companies (utilities and merchant generators) purchase on average 10 percent to 15 percent of coal under "spot" contracts with term shorter than one year. The data are consistent with my testimony regarding standard utility

[6] Source: EIA Form 923 data provided by S&P Global Market Intelligence.

practices, and the data rebut testimony by Mr. Burgess that contracting for more than 50 percent of expected coal requirements should be subject to additional scrutiny and that there has been a trend toward an increasing share of coal purchased under spot contracts.

III. RISK OF SHORTFALL PAYMENTS FOR COAL CONTRACTS

Q. Mr. Burgess recommended that "any penalties incurred by failing to meet the minimum take quantity should not be automatically passed through to customers". Do you agree with that recommendation?

A. No. First, no cost incurred by PacifiCorp is "automatically passed through to customers". All costs are subject to the prudency standard and are only charged to customers with the approval of the Commission. The implication of Mr. Burgess' opinion is that any penalties for failing to meet the minimum take quantity under CSAs should be presumed by the Commission to be imprudent. If the Commission adopts his recommendation, Mr. Burgess opines that "PacifiCorp would be exposed to the same risk factors that a merchant generator would be exposed to."[7]

Q. In your opinion, should PacifiCorp be exposed to the same risk factors as a merchant generator?

A. Of course not. PacifiCorp is a regulated utility, not a merchant generator. PacifiCorp does not have the same benefits as a merchant generator, nor should it have the same risks. Merchant generators earn high profits when power market prices are high and customers run out of power (as happened in Texas in February 2021).

[7] Sierra Club/200, Burgess/27.

Q. Why would the recommendation by Mr. Burgess be harmful to PacifiCorp's customers?

A. This recommendation would create the wrong incentives for PacifiCorp's fuel procurement activities. Rather than focusing solely on procuring a reliable supply of fuel at the lowest reasonable cost, PacifiCorp may change its practices to avoid the risk of incurring penalties under its CSAs. While the cost to customers of purchasing excess coal are small, the costs of running out of coal could be catastrophic. Sierra Club's recommendations are therefore detrimental to customers.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/1400
Witness: Mary M. Wiencke

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Mary M. Wiencke

August 2021

TABLE OF CONTENTS

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

A. Yes.

I. PURPOSE

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to respond to the proposals put forth by Calpine Solutions, LLC (Calpine) and the Staff of the Oregon Public Utility Commission (Staff) regarding the transfer of Renewable Energy Certificates (RECs) to Electricity Service Suppliers (ESSs) for Direct Access Customers.

II. RESPONSE TO CALPINE'S AND STAFF'S RECOMMENDATIONS ON REC TRANSFERS

Q. In light of the recent passage of legislation that allows bundled RECs to be retired by the utility on behalf of an ESS, Calpine proposes two options to implement the change from a REC transfer procedure to a REC retirement procedure.[1] Which option is PacifiCorp's preference?

A. PacifiCorp prefers "Option One". Option One involves the creation of a WREGIS retirement subaccount that is specific to each ESS and renewable portfolio standard (RPS) compliance year. PacifiCorp will then transfer into such retirement subaccount

[1] Calpine/200, Higgins/8.

the bundled and unbundled RECs necessary to meet the RPS obligation for the customers of the ESS that are paying transition adjustment charges to PacifiCorp.[2]

Q. What is the second option?

A. As proposed by Calpine, Option Two involves the same process as Option One for bundled RECs. However, unbundled RECs will continue to follow the old procedure that PacifiCorp and Calpine agreed to in the 2019 Transition Adjustment Mechanism (TAM).[3] Staff proposes a process that is identical to Option Two.[4]

Q. Why is Option One preferable to Option Two?

A. Option One is less administratively burdensome. Option Two requires PacifiCorp to complete two separate processes—a retirement and a transfer—which introduces additional administrative complexity and burden for both the utility and the ESS without any apparent benefit or modified outcome.

Q. Have you reviewed the update provisions proposed by Calpine for REC retirement?[5]

A. Yes, and they are acceptable to PacifiCorp.

Q. Is PacifiCorp proposing to recover administrative costs for the REC retirement process regardless of whether Option One or Option Two is used?

A. Not at this time. However, as the Company gains more experience with the process, PacifiCorp reserves the right to propose a fee or cost recovery method for the administrative costs of these REC transfers in a future TAM or other appropriate proceeding.

---

[2] *Id.*
[3] Calpine/200, Higgins/8-9.
[4] Staff/1300, Gibbens/13.
[5] Calpine/200, Higgins/10-11.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/1500
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Robert M. Meredith

August 2021

TABLE OF CONTENTS

Q. Are you the same Robert M. Meredith who filed reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. I respond to the testimony of Calpine, the Alliance of Western Energy Consumers (AWEC), and Staff of the Public Utility Commission of Oregon (Staff) regarding the Consumer Opt-Out Charge (COOC) and the testimony of Small Business Utility Advocates (SBUA).

II. RESPONSE TO CALPINE, AWEC, AND STAFF TESTIMONY

Q. Please summarize the arguments Calpine, AWEC, and Staff make in their rebuttal testimony for allowing the COOC to have a negative value.

A. Calpine argues that a negative COOC must be viewed within the context of an offset to the fixed generation costs from years six through 10 as well as the base Schedule 200 prices paid for fixed generation costs in the first five years. Calpine then reasons that a negative COOC does not result in cost shifting, because "the calculation recognizes the net power cost savings that will be realized by the non-direct access customers as a result of the departure of the opt-out load." Calpine surmises that the Company's opposition to letting the COOC be negative is related to the timing of how projected benefits from years six through 10 get brought back to direct access participants in the first five years and argues that "(i)f there is any logic to the opt-out mechanism, then it has to be symmetrical."

Similarly, AWEC argues that a negative COOC is appropriate because it reflects the benefits of departing load and criticizes the Company for offering "no support" of cost shifting.

Staff recommends that this issue be taken up more holistically in the generic investigation into direct access in docket UM 2024. However, for this transition adjustment mechanism (TAM) proceeding, Staff recommends that the COOC be allowed to go negative for the same reasons argued by Calpine.

Q. Calpine witness Mr. Kevin C. Higgins describes the total transition costs paid by permanent direct access customers as the sum of the Schedule 296 transition adjustment, the Schedule 296 COOC, and Schedule 200 and then labels the Company's distinction of these different components as "arbitrary". Do you agree?

A. No. The Public Utility Commission of Oregon (Commission) approved the tariff for Schedule 296 which has two very clearly delineated billing components—transition adjustments and the consumer opt-out charge. Significantly, the title for one of these components includes the word "adjustment" signifying a value that could be either positive or negative and the other component includes the word "charge" which signifies a positive value. This distinction was not made arbitrarily. If such a distinction were arbitrary, then it would have been simpler to combine both into a single billing component, but that is not what happened.

Q. Why is this distinction significant?

A. The two billing components serve two different purposes. Transition adjustments reflect the net cost or benefit of freed-up energy that is projected to occur when a direct access participant leaves the Company's system for the five-year period of its transition. The COOC is intended to recover fixed generation costs from permanent direct access participants for years six through 10 and is offset by the projected value of freed-up energy over that same period.

Q. How do the Company's tariffs for other direct access programs compare to Schedule 296?

A. In addition to the five-year permanent direct access program described in Schedule 296, the Company has shorter-term direct access programs for one- and three-year periods that are described in Schedules 294 and 295. Like Schedule 296, both Schedule 294 and 295 contain transition adjustments that reflect the projected net cost or benefit of freed-up energy. The COOC, however, is only present in Schedule 296, the tariff that applies to permanent direct access.

Q. Why is the COOC needed to protect non-participants from unwarranted cost shifting that could result from the permanent direct access program?

A. Unlike the one-year and three-year direct access programs, the intention for the five-year permanent direct access program is for consumers to leave the Company's system for good. Absent a lengthy and onerous return process, those consumers, once fully transitioned, pay the Company for delivery service, but are not supplied with energy from the Company and do not contribute towards the recovery of the Company's generation system. The COOC recognizes that the Company has made investments and planned for serving the load of these consumers, and charges them for part of the stranded cost of the generation system that would otherwise be borne by non-participants.

Q. Please discuss the timeframe over which the COOC is calculated and its significance.

A. The calculation of the COOC considers the fixed cost of generation in years six through 10. Although the lives of fixed generation assets often exceed 10 years, the Company ultimately modified its requested COOC calculation to be over a shorter time horizon as a compromise position to balance the interests of cost shifting and support for the direct access program.[1]

Q. How is the cost of the COOC mitigated for permanent direct access participants?

A. The cost of the COOC is mitigated in two ways. First, it is limited to a 10-year period despite the fact that the lives for many generation assets are longer and the Company plans for a 20-year period in its integrated resource plans. Second, the cost of the COOC is offset by the projected value of freed up energy from the departing load.

Q. If the projected value of freed up energy exceeds the fixed cost of generation in years six through 10, is it appropriate to let the COOC be a negative value?

A. No. The intent of the calculation is to mitigate or offset the cost of fixed generation. If the projected value of freed up energy exceeds the fixed cost of generation, then there should be no consumer opt-out *charge*.

Q. Why would allowing the COOC to be a credit instead of a charge be bad policy?

A. The purpose of the COOC is to prevent unwarranted cost shifting. Providing permanent direct access consumers with a bonus payment for the forecast benefit of freed up energy that exceeds stranded cost undermines that objective and weighs

[1] *In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-out*, Docket No. UE 267, PAC/400, Duvall/3 (Mar. 27, 2014).

heavily against the interests of non-participating consumers. In the Citizens' Utility Board's Rebuttal and Cross Answering Testimony, Mr. Bob Jenks makes some astute observations and raises important concerns regarding the permanent direct access program as it exists in its current form. Until those issues are resolved, it would be appropriate for the Commission to prevent the harm that could be done if the COOC were allowed to be a credit.

Q. Both Calpine and AWEC recommend against deferring this issue to the ongoing generic proceeding covering direct access, docket UM 2024. Do you think this topic should be taken up in docket UM 2024?

A. Yes. I think that it is appropriate for the direct access programs to be evaluated comprehensively in docket UM 2024. Certainly, it would be appropriate for the mechanics of the COOC to be a part of that scope. For the instant proceeding, preserving the interests of non-participating consumers and not permitting the COOC to swing to a payment is the prudent course of action in the interim. Great harm to non-participating consumers could occur if payments were to start being shelled out to consumers choosing to leave the Company's system.

Q. What is your recommendation?

A. I recommend that the Commission reject Calpine, AWEC and Staff's recommendation to allow the COOC be set at a negative value.

III. RESPONSE TO THE TESTIMONY OF SBUA

Q. Please describe SBUA's rebuttal testimony.

A. The content of SBUA's rebuttal testimony continues to be confusing and devoid of any clearly defined recommendations for this TAM proceeding. SBUA's witness

Mr. Darren S. Wertz includes some discussion of Advance Metering Infrastructure, load forecast, and demand charges, but fails to present any actionable conclusions.

Q. How do you respond to SBUA's rebuttal testimony?

A. I have no particular response to SBUA's rebuttal testimony because its position in this proceeding is unclear. My silence on issues raised by SBUA should not be construed as support or acquiescence.

Q. Does this conclude your surrebuttal testimony?

A. Yes.