STATE OF CALIFORNIA GAVIN NEWSOM

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
09/28/22
10:07 AM
A2108004

September 28, 2022

Agenda ID #20998
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 21-08-004:

This is the proposed decision of Administrative Law Judge Shannon O'Rourke. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's November 3, 2022 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:sgu
Attachment

Decision **PROPOSED DECISION OF ALJ O'ROURKE (Mailed 9/28/22)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of PacifiCorp (U901E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue.	Application 21-08-004

DECISION APPROVING PACIFICORP'S 2022 ENERGY COST ADJUSTMENT CLAUSE RATES

TABLE OF CONTENTS

Title **Page**

DECISION APPROVING PACIFICORP'S 2022 ENERGY COST ADJUSTMENT CLAUSE RATES 1
Summary 2
1. Background 2
1.1. Jurisdiction 3
1.2. Summary of PacifiCorp's 2022 ECAC Application 3
2. Evidentiary Standard and Burden of Proof 6
3. Issues Before the Commission 7
4. Balancing Rate 8
5. Offset Rate 8
5.1. Jim Bridger Coal Plant Forecast Fuel Costs 9
5.1.1. Background on Jim Bridger Coal Plant 9
5.1.2. Background on Black Butte Mine Coal Supply Agreement 10
5.1.3. Background on BCC Mine Annual Operating Plan 11
5.1.4. Background on the Use of Incremental Cost versus Average Cost for NPC Calculation and Dispatch 11
5.1.5. Black Butte Mine and BCC Mine Forecast Coal Fuel Costs 12
5.1.5.1. Black Butte Mine Forecast Fuel Costs 13
5.1.5.2. BCC Mine Forecast Fuel Costs 15
5.1.5.3. Use of Incremental Cost Dispatch versus Average Cost Dispatch to Forecast Generation for the Jim Bridger Coal Plant 17
6. Future ECAC Cycle Requirements 19
6.1. Annual Mine Operating Plan and Long-Term Fuel Supply Plan 20
6.2. Adjustments to Future Production Cost Modeling Runs 24
6.2.1. "Must Run"/Economic Cycling 24
6.2.2. "Minimum Take"/ Incremental Dispatch 27
6.3. Timing of Future Coal Supply Agreement Submission 28
6.4. Comparison of "Minimum Take"/"Fixed Production Costs" to Forecast Plant Generation 30
7. Request for Waiver of Certain Modeling Requirements from D.20-12-004 30
8. ECAC Rate Spread and Rate Design 32
9. Comments on Proposed Decision 33
10. Assignment of Proceeding 33
Findings of Fact 33
Conclusions of Law 37
ORDER 38

DECISION APPROVING PACIFICORP'S 2022 ENERGY COST ADJUSTMENT CLAUSE RATES

Summary

This decision authorizes PacifiCorp d/b/a Pacific Power (PacifiCorp) to modify its Energy Cost Adjustment Clause (ECAC) rates to allow for an annual increase in revenues for 2022 of approximately $3.4 million from its previously authorized rates. These new rates shall become effective upon the filing of an advice letter, subject to the Energy Division determining the rates comply with this decision. In addition, this decision directs PacifiCorp to conduct additional analysis for future ECAC cycles intended to ensure PacifiCorp is actively considering options to reliably and economically serve its customers' electricity needs with alternatives to coal.

Application 21-08-004 is closed.

1. Background

PacifiCorp d/b/a Pacific Power (PacifiCorp) is a multi-jurisdictional utility providing electric retail service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp serves approximately 48,000 customers in Del Norte, Modoc, Shasta, and Siskiyou counties in Northern California.

On August 3, 2021, PacifiCorp filed an application for approval of its 2022 Energy Cost Adjustment Clause (ECAC) and greenhouse gas (GHG)-Related Forecast and Reconciliation of Costs and Revenue (Application). Sierra Club filed a timely protest on September 2, 2021 and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed a timely protest on September 7, 2021.

The assigned Administrative Law Judge (ALJ) held a prehearing conference (PHC) on November 16, 2021 to address the issues, schedule, and other matters relevant to the management of the proceeding. On

November 22, 2021, the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo).

On January 7, 2022, PacifiCorp filed an amended application to incorporate the ECAC rates that were approved in the 2021 ECAC proceeding in Decision (D.) 21-11-001 and to utilize the new GHG Climate Credit procedure adopted in D.21-08-026.

On January 7, 2022, PacifiCorp and Cal Advocates jointly moved for approval of their partial settlement and stipulation regarding PacifiCorp's Application that resolved all issues with respect to the GHG emission allowance program costs and climate credits. On March 17, 2022, the Commission adopted D.22-03-014, approving PacifiCorp's 2022 GHG-related costs and allowance proceeds, and authorized PacifiCorp to reflect the changes in rates.

An evidentiary hearing was held on May 25, 2022.

On June 23, 2022, PacifiCorp and Sierra Club filed opening briefs. On July 25, 2022, PacifiCorp and Sierra Club filed reply briefs.

1.1. Jurisdiction

The Commission authorized PacifiCorp to implement the ECAC mechanism to recover its net power costs (NPC)[1] in D.06-12-011. Since then, PacifiCorp has filed annual applications to adjust its ECAC rates.[2]

1.2. Summary of PacifiCorp's 2022 ECAC Application

The ECAC mechanism includes two rate components: the Offset Rate and the Balancing Rate. The primary role of the Offset Rate is to reflect the forecast of

[1] NPC is the sum of the company's fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

[2] Application (A.) 20-08-002, A.19-08-002, A.18-08-001, A.17-08-005, A.16-08-001, A.14-08-002, A.13-08-001, A.12-08-003, A.11-08-001, A.10-08-003, A.09-07-032, and A.08-08-003.

NPC and the fuel stock carrying charge for the upcoming year. In contrast, the primary role of the Balancing Rate is to true-up the previous NPC forecast currently in rates with the actual NPC. In previous ECAC filings, PacifiCorp used the production cost model, the Generation and Regulation Initiatives Tool (GRID), to simulate operation of its power system on an hourly basis, predict incremental dispatch of its existing generation resources, and forecast fuel costs for the purpose of calculating NPC. PacifiCorp transitioned to the Aurora model for this purpose for the 2022 ECAC.[3]

Pursuant to D.06-12-011, the Balancing and Offset Rates are to be updated each year if the new rate varies from the current rate by five percent or more.[4] PacifiCorp's proposed changes to the Balancing and Offset Rates for 2022 exceed the five percent threshold.[5]

In its Application, PacifiCorp requests approval to increase the Balancing Rate and the Offset Rate. Specifically, PacifiCorp requests:

- An increase of $2.4 million to the Balancing Rate, or a new Balancing Rate of $4.25 per megawatt-hour (MWh) compared to the $1.05 per MWh currently in effect.
- An increase of $0.9 million to the Offset Rate, or a new Offset Rate of $25.15 per MWh compared to the $23.88 per MWh currently in effect.

The proposed increases to the Balancing Rate and Offset Rate would result in a net increase in ECAC rates of approximately $3.4 million.[6]

---

[3] PacifiCorp Application at 9.

[4] D.06-12-011, 2.3.1 Energy Cost Adjustment Clause at Attachment A.

[5] PacifiCorp Application at 7-8.

[6] PacifiCorp Application at 5.

Rate impacts in this proceeding were reported as the combined effect of PacifiCorp's proposed ECAC and GHG cost recovery changes. While PacifiCorp's GHG-related rate changes were approved earlier this year in D.22-03-014, the combined effect of the proposed ECAC and GHG cost recovery rate changes are provided below:[7]

Table 1: Proposed Price Changes by Customer Class

Customer Class	Proposed Rate Change	
	Dollars	**Percent**
Residential	$3,430,000	6.5%
Commercial/Industrial	$2,389,000	6.9%
Irrigation	$828,000	6.6%
Lighting	$38,000	5.6%
Overall	**$6,685,000**	**6.6%**

PacifiCorp attributes the increase in the Balancing Rate to increased purchased power costs and transactions in 2021 relative to the forecast, as well as to outstanding collections from 2020 that were rolled over to 2021.[8] With regard to outstanding collections, PacifiCorp states that because its ECAC proceedings have been fully litigated in recent years, its ECAC rates have not gone into effect until late in the relevant year, resulting in an annual under-collection that must be rolled over into the Balancing Rate for the subsequent year.[9] It attributes the increase in the Offset Rate to an increase in market purchase costs and

[7] *Id.* at 2.

[8] *Id.* at 4.

[9] *Id.* at 5.

transactions, and notes that the higher purchased power costs were partially offset by an increase in wholesale sales and a decrease in coal fuel expense.[10]

2. Evidentiary Standard and Burden of Proof

All rates and charges collected by a public utility must be "just and reasonable,"[11] and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified."[12] The Commission requires that utility applicants demonstrate with admissible evidence that the costs which they seek to include in rates are just and reasonable, while the applicant "has the burden of affirmatively establishing the reasonableness of all aspects of its request."[13]

The Commission has confirmed on numerous occasions that the appropriate legal standard in ratesetting matters is that of the "preponderance of the evidence."[14] The Commission has also acknowledged that it has, at times, incorrectly referred to the "preponderance of the evidence" standard as "clear and convincing evidence."[15]

The distinction is important. Where clear and convincing evidence places a heavy burden on the applicant and does not require intervenors to prove the contrary, preponderance of the evidence is generally defined "in terms of probability of truth, *e.g.*, 'such evidence as, when weighed with that opposed to

[10] PacifiCorp Opening Brief at 3.

[11] Public Utilities (Pub. Util.) Code § 451.

[12] Pub. Util. Code § 454.

[13] D.15-11-021 at 10.

[14] D.11-05-018 at 68; D.12-11-051 at 9; D.12-12-030 at 44; D.14-08-032 at 17; D.15-11-021 at 8-9; and D.16-12-063 at 9.

[15] D.09-03-025 at 8.

it, has more convincing force and the greater probability of truth'."[16] In other words, the applicant must present more evidence that supports the requested result than would support an alternative outcome. Still speaking in general terms, the counterpoint to the applicant's burden of proof is the burden the Commission places on intervenors in proceedings, the burden of producing evidence:

> [W]here other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof. The burden of going forward to produce evidence relates to raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position. Where this counterpoint causes the Commission to entertain a reasonable doubt regarding the utility's position, and the utility does not overcome this doubt, the utility has not met its ultimate burden of proof.[17]

Thus, there is a difference between the applicant, who has the ultimate burden of proof in a ratesetting matter, and which party has the burden of producing evidence once a prima facie showing has been made.[18] The record in this proceeding has been considered within this legal framework.

3. Issues Before the Commission

This decision addresses the following issues:

1. Whether PacifiCorp's proposed Balancing Rate is reasonable.
2. Whether PacifiCorp's proposed Offset Rate is reasonable.
3. Whether PacifiCorp's proposed rate spread and rate design is reasonable.

---

[16] D.08-12-058 at 19 (citing Witkin, Calif. Evidence, 4th Edition, Vol. 1 at 184).

[17] D.87-12-067 at 27; also, D.07-11-037, footnote 41 at 101-102.

[18] D.07-11-037, footnote 41 at 101.

4. Balancing Rate

The ECAC Balancing Rate is comprised of the following components: NPC, fuel stock carrying charge, Air Resources Board (ARB) administrative costs, net metering surplus compensation, Renewable Energy Credit (REC) purchases for Renewables Portfolio Standard (RPS) compliance, Performance Tax Credits, and start-up fuel costs. These components, as well as the interest accumulated on the balance of the ECAC balancing account, total approximately $3,106,894. When divided by projected California retail sales of 747,460 megawatt-hours (MWh) and grossed up for franchise fees and uncollectible accounts expense, PacifiCorp's proposed 2022 Balancing Rate is $4.25 per MWh.[19]

The components of the Balancing Rate are uncontested and are adequately supported by testimony and exhibits. We therefore find PacifiCorp's requested Balancing Rate of $4.25 per MWh to be reasonable and it is adopted.

5. Offset Rate

The ECAC Offset Rate typically includes the same components as the Balancing Rate, and reflects the forecast costs for the upcoming year of the following components: [20]

- NPC, which is comprised of the following subcomponents:
    - Forward price curve, forecast loads, normalized hydro generation, forecast coal costs, wholesale sales and purchases of electricity and natural gas, thermal plant capability, and wheeling expenses.

---

[19] Exhibit PAC/100 at 9-10.

[20] PacifiCorp Application at 8.

- Fuel stock carrying charge, ARB administrative costs, [21] net metering surplus compensation, REC purchases for RPS compliance, Performance Tax Credits, and start-up fuel costs. [22]

These components total approximately $18,419,279. When divided by projected California retail sales of 747,460 MWh, and then grossed up for franchise fees and uncollectible accounts expense, PacifiCorp's proposed 2022 Offset Rate is $25.15 per MWh.[23]

The only element of the Offset Rate that is contested in this proceeding is the forecast coal fuel costs for the Jim Bridger coal plant. This issue is discussed in the subsequent section. The other components of the Offset Rate are uncontested and are adequately supported by testimony and exhibits. We therefore find the uncontested components of PacifiCorp's Offset Rate to be reasonable.

5.1. Jim Bridger Coal Plant Forecast Fuel Costs

5.1.1. Background on Jim Bridger Coal Plant

The Jim Bridger plant is a 2,120 megawatt (MW) coal-fired power plant that consists of four 530 MW generating units.[24] The plant is located in Sweetwater County, Wyoming and is co-owned by PacifiCorp and Idaho Power. Jim Bridger Units 1 and 2 are scheduled to convert to natural gas by the end of

---

[21] The inclusion of ARB implementation fees and mandatory reporting and verification costs required to implement Assembly Bill 32 is consistent with D.12-03-022. In that decision, the Commission authorized PacifiCorp to establish a memorandum account to seek recovery of these costs.

[22] The inclusion of start-up fuel costs as part of PacifiCorp's ECAC was approved in D.20-02-025 at 6.

[23] Exhibit PAC/100 at 13.

[24] Exhibit PAC/801 at 6.

2023 and all four units are scheduled to close by the end of 2037.[25] The Jim Bridger plant is currently served by two fuel sources: 1) coal secured through a coal supply agreement with third-party owned Black Butte mine, and 2) coal provided by the Bridger Coal Company (BCC) mine, which is a jointly-owned affiliate mine of PacifiCorp and Idaho Power.[26]

5.1.2. Background on Black Butte Mine Coal Supply Agreement

D.21-11-001 requires PacifiCorp to analyze the prudence of all new coal supply agreements it executes compared to alternative resources and to provide that analysis as part of the ECAC application where it proposes those costs for inclusion in rates.[27] PacifiCorp's existing coal supply agreement with the Black Butte mine expired in April 2022, eight months after PacifiCorp filed its 2022 ECAC application. PacifiCorp states that because it had not yet renegotiated a new coal supply agreement with the Black Butte mine when it submitted its 2022 ECAC application, it used a "proxy fuel cost" estimate for modeling the NPC for the portion of the year not covered by the pre-existing contract (May through December 2022).[28] PacifiCorp states that it intends to submit the new Black Butte coal supply agreement and accompanying analysis required by D.21-11-001 in its 2023 ECAC application, which will be when it proposes to have the actual costs of the coal supply agreement, including those for 2022, included in rates.[29]

[25] *Id.* at 233.

[26] Exhibit PAC/800 at 13.

[27] D.21-11-001 at Ordering Paragraphs 4-5.

[28] PacifiCorp Opening Brief at 8.

[29] *Id.* at 10-11.

5.1.3. Background on BCC Mine Annual Operating Plan

As the BCC mine is an affiliate mine owned by PacifiCorp and Idaho Power, there is no third-party coal supply agreement for delivery of coal from the mine. In contrast, forecast fuel costs from the BCC mine are based on an annual operating plan.[30] PacifiCorp states that each year, BCC develops several mine plans with varying levels of production and PacifiCorp and Idaho Power select the plan they determine to be least cost, least risk, and best fit of forecast generation.[31] PacifiCorp also states that the mine plan takes into account operational, geologic, and safety considerations that affect the amount of coal to be mined in a given year.[32]

5.1.4. Background on the Use of Incremental Cost Versus Average Cost for NPC Calculation and Dispatch

PacifiCorp uses the Aurora production cost model to predict incremental dispatch of its existing generation resources and to forecast coal fuel costs for the purpose of calculating NPC in this proceeding. The fundamental objective of the model is to meet the forecast load at the lowest possible cost.[33]

Because NPC modeling is a short-term forecast that views the existing generation fleet and topology as fixed, its focus is on cost-based dispatch optimization using the incremental cost of production.[34] The incremental cost of production is the cost required to increase production at a generation unit by one

---

[30] Exhibit SC-1 at 18.

[31] Exhibit PAC/800 at 15.

[32] *Ibid.*

[33] Exhibit PAC/700 at 20.

[34] *Id.* at 18.

MWh, and primarily reflects only fuel costs. If the cost to generate is less than the market price for electricity, the resource is dispatched.[35] In PacifiCorp's NPC forecasting, the calculation of incremental costs excludes the cost of coal subject to "minimum take" provisions in coal supply agreements.[36] "Minimum take" contract provisions require payment equal to the full price of coal if PacifiCorp fails to take a specified minimum contract volume. [37]

The average cost of production is the ratio of the total cost of production for a plant to the total energy produced. The total cost of production would include startup costs, fuel costs, operation costs, and maintenance costs.[38]

As has been recognized by this Commission in the past, the use of incremental costs to inform short-term dispatch decisions is considered standard practice.[39]

5.1.5. Jim Bridger Forecast Coal Fuel Costs

Sierra Club's predominant argument is that the forecast generation and associated fuel volumes for the Jim Bridger plant are too high and that the approximately $2.63 million[40] in California-allocated costs should be disallowed.[41] Sierra Club presents arguments specific to the Black Butte mine and the BCC mine modeling assumptions, and also presents an overarching

---

[35] *Id.* at 24.

[36] *Id.* at 24.

[37] *Id.* at 30.

[38] *Id.* at 23-24.

[39] D.20-12-004 at 15.

[40] Sierra Club Opening Brief at 21.

[41] *Id.* at 20.

argument regarding the assumptions used to model dispatch for the Jim Bridger plant.

5.1.5.1. Black Butte Mine Forecast Fuel Costs

Sierra Club argues that PacifiCorp's "proxy fuel cost" estimate for the period after the existing coal supply agreement expired (May through December 2022), is based on higher volumes of purchased coal than is reasonable. As an initial matter, Sierra Club asserts that because PacifiCorp did not have an executed coal supply agreement with Black Butte mine after April 2022, it should not have assumed Black Butte would continue to supply Jim Bridger with fuel after that date without first evaluating whether cleaner alternatives would be more economic.[42] Secondly, Sierra Club argues that even if PacifiCorp did assume coal would be supplied by the Black Butte mine, it should not have assumed that there would be a "minimum take" requirement for coal from the mine.[43] Sierra Club further asserts that the "minimum take" requirement could be driving generation levels overall at the Jim Bridger plant because the "minimum take" volume was the same quantity of coal that the model forecast purchasing from the mine.[44]

PacifiCorp argues it used the appropriate approach for estimating fuel costs for the period after the coal supply agreement with Black Butte expired. It states that the use of "proxy fuel cost" estimates when actual contract prices are not available is logical and standard industry practice in order for NPC forecasts

[42] *Id.* at 6.

[43] *Id.* at 7.

[44] *Id.* at 9.

to accurately reflect actual operations.[45] To prepare the estimate, PacifiCorp states that it obtained indicative pricing from the coal supplier, applied its professional judgment, and considered other factors such as preliminary generation forecasts.[46] It additionally states that the alternatives analysis required by D.21-11-001 will be provided when it submits the actual renegotiated coal supply agreement with Black Butte in the 2023 ECAC proceeding.[47]

PacifiCorp also argues that it was reasonable to assume a "minimum take" obligation in its estimate because in practice, nearly all of its coal supply agreements include such a requirement[48] and because the coal supplier communicated that any future contract would include a "minimum take" provision.[49] PacifiCorp further states that the overall projected generation at the Jim Bridger plant was above the cumulative "minimum take" and "fixed production cost" levels forecast for Black Butte and BCC, which demonstrates that "minimum takes" are not driving generation at the plant.[50]

Although an alternatives analysis could be useful for illustrating whether PacifiCorp's "proxy fuel cost" assumption for the Black Butte mine was reasonable, PacifiCorp is not required to conduct such an analysis, and its absence is not evidence that the forecast fuel costs in this instance are unreasonable. In light of the timing dynamics and operational realities, including the contracting history with the mine, it was reasonable for PacifiCorp to base its

---

[45] PacifiCorp Opening Brief at 15.

[46] Exhibit PAC/800-C at 5.

[47] PacifiCorp Opening Brief at 10-11.

[48] PacifiCorp Reply Brief at 3.

[49] Exhibit PAC/800-C at 7.

[50] PacifiCorp Opening Brief at 16.

"proxy fuel cost" estimate for May through December 2022 on the Black Butte mine and to assume there would be a "minimum take" obligation. We also consider that Sierra Club did not raise issue with the assumed fuel prices. We therefore find the preponderance of the evidence supports a finding that the "proxy fuel cost" estimate for the Black Butte mine was reasonable.

The actual renegotiated coal supply agreement and associated costs will be reviewed and considered in the 2023 ECAC. After Commission review, if any costs associated with the coal supply agreement that were incurred in 2022 are found to be unreasonable, they can be returned to ratepayers through an adjustment to the Balancing Rate.

We are also persuaded that because the overall forecast generation for Jim Bridger is higher than the combined "minimum take" and "fixed production cost" obligations for Black Butte and BCC, we cannot conclude that the "minimum take" volumes were driving generation at the plant.

5.1.5.2. BCC Mine Forecast Fuel Costs

Sierra Club has similar concerns with the volume of coal purchases forecast for the BCC mine. It argues that because PacifiCorp did not provide analysis demonstrating it considered alternative production volumes for the mine other than the one used for modeling NPC, there is no evidence the mine plan is in the best interests of ratepayers.[51] Sierra Club also argues PacifiCorp should not have assumed there would be "fixed production costs" for the BCC mine, which it asserts ensured the forecast produced generation levels for the Jim Bridger plant that justify the BCC mine volumes.[52]

[51] Sierra Club Opening Brief at 14.

[52] *Ibid.*

PacifiCorp refutes Sierra Club's assertion that the BCC mine plan was not well-supported, stating that although a single plan was used for NPC forecasting, various forecasts were used to develop the mine plan and that the mine plan includes detailed cost figures for every aspect of the mine.[53] PacifiCorp also states that the volume and cost per ton of BCC coal supplies are similar to those approved in the two previous ECAC proceedings.[54] PacifiCorp further points out that Sierra Club has not identified any specific costs in the BCC mine plan that are unreasonable.[55] With regard to Sierra Club's argument that "fixed production costs" should not have been assumed, PacifiCorp asserts that BCC cannot reduce overall costs by producing less coal, because over the one-year ECAC planning period, BCC's production costs include unavoidable costs,[56] and it is therefore appropriate to treat these fixed costs the same way as "minimum take" obligations in the NPC forecasting process.[57] Finally, as discussed in the previous section, PacifiCorp states that the overall projected generation at the Jim Bridger plant was above the combined "minimum take" and "fixed production cost" levels forecast for Black Butte and BCC, which it holds demonstrates that "minimum takes" are not driving generation at the plant.[58]

Although PacifiCorp presents a single scenario for NPC modeling purposes, this approach is consistent with the approach used in prior years and no evidence was presented to demonstrate that this scenario was unreasonable.

---

[53] PacifiCorp Reply Brief at 4.

[54] PacifiCorp Opening Brief at 17.

[55] *Id.* at 18.

[56] Exhibit PAC/800 at 15.

[57] *Id.* at 14-15.

[58] PacifiCorp Opening Brief at 16.

In contrast, the generation volumes and costs that resulted from the scenario were similar to those approved by the Commission in prior ECACs and it is reasonable to expect that for modeling purposes, certain costs would be fixed over the short-term. We are also persuaded that because the overall forecast generation for Jim Bridger is higher than the combined "minimum take" and "fixed production cost" obligations for Black Butte and BCC, we cannot conclude that the "fixed production costs" were driving generation levels at the plant. We therefore find that the preponderance of the evidence supports a finding that the BCC forecast fuel costs are reasonable.

5.1.5.3. Use of Incremental Cost Dispatch versus Average Cost Dispatch to Forecast Generation for the Jim Bridger Coal Plant

With regard to overall forecast generation at the Jim Bridger plant, Sierra Club argues that PacifiCorp should not have used "minimum take" /"fixed production cost" constraints to model NPC and that using such constraints results in higher costs for customers than if those requirements were not imposed. Asserting that "minimum take"/"fixed production cost" constraints should not be used is essentially an argument that average cost dispatch should be used to model dispatch of the plant instead of incremental cost dispatch.[59]

To support its position that the use of "minimum take"/"fixed production costs" constraints resulted in unreasonable costs, Sierra Club cites three recent average cost model runs that forecast significantly lower generation levels than those PacifiCorp includes in its application.[60]

---

[59] Sierra Club Opening Brief at 14.

[60] *Id.* at 14.

The first model run is an average cost model run conducted in the Oregon Public Utilities Commission Transition Adjustment Mechanism (TAM) proceeding.[61] The TAM model run forecast lower generation and fuel costs than PacifiCorp's incremental cost dispatch model run.[62] The second model run is an average cost model run conducted for this proceeding. This model run also forecast lower generation than PacifiCorp's incremental cost dispatch model run, but forecast higher costs because, unlike the Oregon TAM model run, fixed costs that PacifiCorp asserts are unavoidable were included.[63] The third model run is an average cost model run conducted at the request of the Oregon Public Utilities Commission for PacifiCorp's 2021 Integrated Resource Plan. This model run dealt with a 20-year time horizon and forecast lower generation than PacifiCorp's incremental cost dispatch model run.[64]

PacifiCorp argues the use of average cost modeling for NPC forecasting is inconsistent with basic economic principles and has been rejected previously by the Commission.[65] PacifiCorp identifies the following issues with the model runs: The Oregon TAM run excluded fixed costs for the plant that could not be avoided and assumed a coal dispatch price that could not be delivered under real world operations at the reduced output level that resulted from the modeling, due to economies of scale;[66] the 2022 ECAC proceeding run produced a higher NPC than the run PacifiCorp used for its application when the costs associated

---

[61] The Oregon TAM proceeding is an analogous proceeding to the ECAC proceeding.

[62] Sierra Club Opening Brief at 15; also Exhibit SC-01 at 25.

[63] Sierra Club Opening Brief at 15; also Exhibit SC-01 at 28.

[64] Sierra Club Opening Brief at 18; also Exhibit SC-01 at 32.

[65] Exhibit PAC/700 at 23.

[66] PacifiCorp Reply Brief at 17.

with the "minimum take" requirements are included;[67] and, the 2021 Integrated Resource Plan run was over a long-term planning horizon that provides more flexibility than the one-year ECAC horizon, and included unrealistic assumptions that there would be no "minimum take" requirements for the plant in the future and that large volumes of coal could be procured from alternative suppliers.[68] PacifiCorp further argues that reducing Jim Bridger generation to the levels in the runs Sierra Club references would negatively impact reliability.[69]

Sierra Club's argument that average cost dispatch should have been used in forecasting NPC for Jim Bridger is based on the premise that PacifiCorp would not be subject to "minimum take" or "fixed production cost" obligations for the fuel that supplies the plant in 2022 and therefore customers would not incur any costs if fuel volumes were below certain levels. While over a longer-term planning horizon, it may be reasonable to assume these types of costs are not fixed, based on the record in this proceeding, it was reasonable for PacifiCorp to assume there would be "minimum take" or "fixed production cost" obligations over the one-year planning horizon. When modeling accounts for these obligations, we find the evidence supports that the least-cost approach to estimating 2022 NPC for Jim Bridger is the incremental cost dispatch approach used by PacifiCorp.

6. Future ECAC Cycle Requirements

Although PacifiCorp has adequately justified its forecast fuel costs for the 2022 ECAC, we also are cognizant that this ECAC proceeding occurs within the broader context of California's effort to rapidly decarbonize its electricity

[67] *Id.* at 18-19

[68] *Id.* at 19-20.

[69] *Id.* at 22-23.

supply.[70] While the Commission has implemented policies and regulations to help ensure the state reaches that goal, we seek to continually identify approaches to help accelerate the transition to carbon neutrality. Within this framework, we reiterate to PacifiCorp the imperative of continually revisiting its long and short-term resource and power purchase planning to identify whether it can reliably and economically serve its customers' electricity needs with alternatives to coal at a faster pace than it has currently planned. In this section we address recommendations by Sierra Club intended to enhance transparency in how PacifiCorp conducts its resource and power purchase planning and to provide guidance on additional requirements for future ECAC cycles to help ensure PacifiCorp actively heeds the Commission's directive.

6.1. Annual Mine Operating Plan and Long-Term Fuel Supply Plan

Sierra Club recommends the Commission require PacifiCorp to submit its annual BCC mine operating plan and conduct an evaluation of alternative mine plans as part of each ECAC application. [71] Sierra Club also requests that the alternative mine plans include significantly reduced production from the previous year (approximately 50 percent).[72] Doing so, it asserts, would ensure that PacifiCorp is considering a range of alternatives, including replacing Jim Bridger with lower cost resources, and treat the mine plan similarly to the coal supply agreements.[73] Sierra Club also recommends that PacifiCorp be

[70] Senate Bill 100 (De León, Chapter 312, Statutes of 2018).

[71] Sierra Club Opening Brief at 22.

[72] Exhibit SC-01 at 42.

[73] Sierra Club Opening Brief at 23.

required to identify which costs in its mine plan are considered fixed and therefore could not be avoided based on volume of coal produced.[74]

Sierra Club further identifies that the Long-Term Fuel Supply Plan for Jim Bridger is a vehicle for systemically reviewing fueling costs for the plant, as it provides a more holistic evaluation of total fueling than the annual operating plans.[75] It points out that the Oregon Public Utilities Commission recently directed PacifiCorp to update its Jim Bridger Long-Term Fuel Supply Plan to evaluate the consequences of fueling the plant only from the Black Butte mine or only from the BCC mine and to ensure that the plan allows the plant to decrease output as new generation comes online.[76] PacifiCorp updated the plan in April 2022 using the GRID model. Sierra Club identifies that PacifiCorp only periodically creates a Long-Term Fuel Supply Plan and that it is usually done only at the request of a regulatory commission. It therefore recommends that, in addition to requiring the annual mine operating plan, the Commission should require annual updates to the Jim Bridger Long-Term Fuel Supply Plan.[77] Sierra Club also recommends the Long-Term Fuel Supply Plan: 1) be modeled with software that is capable of handling multiple fuel price points for Jim Bridger, such as Aurora or Plexos;[78] and 2) "minimum take" constraints be excluded, unless they are included in a coal supply agreement or affiliate mine plan that has already been deemed prudent by the Commission.[79]

---

[74] *Ibid.*

[75] Exhibit SC-01 at 38.

[76] *Id.* at 38.

[77] Sierra Club Opening Brief at 22.

[78] *Id.* at 23-24.

[79] *Id.* at 25.

PacifiCorp believes that it should not be required to submit the annual mine plan for review or be required to conduct an alternatives analysis. It states that although an affiliate mine operating plan can inform the reasonableness review of fuel costs, there are many differences between multi-year coal supply agreements and annual mine plans, including length of time covered, flexibility over long-term production provided by mine ownership, and market-based pricing from third parties versus cost-based pricing from an affiliate.[80] PacifiCorp also points out that annual mine operating plans are already subject to prudency review as part of the annual ECAC proceedings and can be reviewed as part of discovery, as has been the custom in recent years.[81]

PacifiCorp also acknowledges that it periodically prepares a Long-Term Fuel Supply Plan for the Jim Bridger plant,[82] and states that it will update its Long-Term Fuel Supply Plan for its 2023 Integrated Resource Plan.[83] PacifiCorp argues that annual filing of a long-term resource plan is inefficient and that there is no need for an annual update because the bi-annual Integrated Resource Plan filings and the ad hoc updates to the Long-Term Fuel Supply Plans are sufficient for ensuring PacifiCorp considers the long-term utilization of the Jim Bridger plant amongst other resources.[84] PacifiCorp also states that any future modeling of the kind Sierra Club contemplates would be conducted using Aurora or Plexos because GRID will be phased out in 2022.[85]

---

[80] Exhibit PAC/800 at 11.

[81] PacifiCorp Reply Brief at 9.

[82] Exhibit PAC/800 at 16.

[83] *Id.* at 17.

[84] PacifiCorp Reply Brief at 11.

[85] *Id.* at 11-12.

While we agree that reviewing PacifiCorp's annual mine operating plan is an important part of the annual ECAC process, the mine plans are already reviewed annually through discovery. We therefore do not see a need to impose a specific requirement that they be filed. With regard to an alternatives analysis, we believe that such an analysis would be valuable, but find that it would be more useful for this to be done through the Long-Term Fuel Supply Plan than the annual mine plan. The Long-Term Fuel Supply plan provides more flexibility to credibly consider alternatives because it utilizes a multi-year horizon rather than the shorter-term annual horizon of the mine operating plan.

We would expect the results of the analysis in any Long-Term Fuel Supply Plan would inform PacifiCorp's annual mine operating plan and the Commission's review of the reasonableness of that plan. We therefore require PacifiCorp to update its Jim Bridger Long-Term Fuel Supply Plan for the 2024 ECAC. This will align with PacifiCorp's planned update for its 2023 Integrated Resource Plan,[86] and provide sufficient time for the plan to inform its 2024 ECAC filing. When PacifiCorp updates the Jim Bridger Long-Term Fuel Supply Plan, it shall at a minimum consider the long-term fueling options for Jim Bridger, including alternative fueling options for Units 3 and 4, and whether the plant could be retired early or have its generation reduced through displacement by alternative resources. The updated plan shall also include an informational scenario that utilizes average cost dispatch. We decline to require PacifiCorp to file annual updates to the Long-Term Fuel Supply Plan at this time. In future proceedings, the Commission can consider whether to require updates to the Long-Term Fuel Supply Plan on a recurring or ad hoc basis.

[86] Evidentiary Hearing Transcript Volume 1 at 116.

6.2. Adjustments to Future Production Cost Modeling Runs

Sierra Club argues that PacifiCorp's NPC modeling isn't producing the most economic generation forecast because it utilizes "must run" and "minimum take" constraints. [87] It therefore recommends the Commission require PacifiCorp make changes to the Aurora model inputs for future ECAC proceedings.[88]

6.2.1. "Must Run"/Economic Cycling

Economic cycling is the practice of taking a coal plant offline for a period of time and replacing it with other resources for the purpose of avoiding fuel costs.[89] PacifiCorp utilizes a "must run" constraint for its coal plants when modeling NPC, which prohibits the plants from economically cycling. PacifiCorp states that it is appropriate to use a "must run" constraint for coal plants because the model is intended to forecast NPC under normal conditions and under normal conditions coal plants infrequently cycle. Instead, in actual operations, a coal plant cycles between minimum and maximum operating levels, and when its dispatch price is higher than the price of other resources, it can be ramped down to minimum operating levels, but still continue to generate, thereby avoiding additional startup costs and reliability risks.[90] At Sierra Club's request, PacifiCorp modeled NPC without the "must run" constraint, which resulted in a forecast increase to the NPC and forecast reliability issues.[91]

---

[87] Sierra Club Opening Brief at 25.

[88] *Ibid.*

[89] Evidentiary Hearing Transcript Volume 1 at 37.

[90] Exhibit PAC/700 at 32-34.

[91] *Id.* at 34-35.

While Sierra Club acknowledges there are instances where it does not make economic sense to cycle a coal plant,[92] it argues that PacifiCorp's recent analysis, which allowed all coal plants to cycle simultaneously year-round, demonstrates that PacifiCorp is not meaningfully evaluating economic cycling as an approach.[93] Sierra Club hypothesizes that limiting economic cycling to a select number of coal units at any one time may produce economic results.[94] Sierra Club therefore recommends the Commission direct PacifiCorp to conduct a study to further analyze the benefits of economic cycling, including limiting economic cycling to particular coal units, times of year, and/or the lengths of time that a unit would be offline.[95]

PacifiCorp believes Sierra Club's recommendation is too broad and undefined to be of use to either the company or the Commission.[96] It further asserts that the costs of alternative resources at present market prices are substantially higher than its coal fleet, therefore cycling coal plants is highly unlikely to reduce costs for customers.[97]

While the Commission determined in D.21-11-001 that reliability concerns with economic cycling outweighed the potential benefit of removing the "must run" constraint in NPC forecasting for existing contracts,[98] it also found that as

[92] Exhibit SC-01 at 50.

[93] Sierra Club Opening Brief at 29.

[94] *Ibid.*

[95] *Id.* at 31.

[96] PacifiCorp Reply Brief at 14.

[97] PacifiCorp Opening Brief at 20–21.

[98] D.21-11-001 at 16.

PacifiCorp's portfolio evolves, renewable resources increase, and coal plants near retirement dates, the notion that coal plants "must run" in perpetuity cannot be assumed.[99]

Although the disparity between the costs for PacifiCorp's coal fleet and alternative resources in the market is presently large, we see the merit in a more targeted economic cycling analysis for informational purposes. A more nuanced analysis of how economic cycling of PacifiCorp's coal units could be deployed will inform understanding of whether economic cycling could be beneficial for customers in certain instances. Although Sierra Club's proposed categories for analysis are appropriate, we believe they would benefit from further refinement. We therefore direct PacifiCorp to convene a meeting with interested parties to receive input on the specific scenarios that PacifiCorp should model for its study. Within seven days of the issuance date of this decision, PacifiCorp shall notify the service list of this proceeding and the 2023 ECAC proceeding of its intention to convene a meeting to receive input on scenarios for the study. PacifiCorp is directed to supplement its testimony in the 2023 ECAC proceeding within 60 days of the issuance date of this decision with the results of the study. Additionally, PacifiCorp shall update the economic cycling study on an annual basis and submit the results in its ECAC application annually. For these updates, PacifiCorp shall seek input from interested parties on scenarios before conducting the updates by notifying the service list of the most recently opened ECAC proceeding. PacifiCorp shall also detail its scenario refinements, input from stakeholders, and study results in its annual ECAC application.

---

[99] *Id.* at 23.

6.2.2. "Minimum Take"/Incremental Dispatch

Sierra Club acknowledges D.21-11-001 determined that imposing "minimum take" constraints for coal supply agreements that have "minimum take" requirements in them is likely in the best interest of ratepayers, as there is a preexisting commitment to purchase the coal under contract.[100] While not disputing that this approach may be appropriate when there are Commission-approved coal supply agreements with "minimum take" requirements, Sierra Club argues this approach should not be allowed in instances where there is no Commission-approved contract, like for the BCC mine because it is an affiliate mine or for the Black Butte mine in 2022 where a coal supply agreement expired and a new one was yet to be executed.[101] In instances like these, Sierra Club recommends PacifiCorp be required to remove "minimum take" assumptions to allow the model to select the most economically efficient coal consumption level.[102]

PacifiCorp identifies that removing "minimum take" requirements would have the practical consequence of replacing incremental cost dispatch in the Aurora model with average cost dispatch, which the Commission determined in D.20-12-004 and D.21-11-001 is an approach that increases costs and is contrary to basic economic principles.[103] PacifiCorp also asserts that for instances like the Black Butte coal supply agreement, Sierra Club has presented no persuasive

---

[100] *Id.* at 15.

[101] Sierra Club Opening Brief at 27.

[102] *Id.* at 27-28.

[103] PacifiCorp Reply Brief at 13; also D.20-12-004 at 13, 19, 30 and D.21-11-001 at 12-13, 15.

justification for why "minimum take" requirements should not be applied to an estimate of coal fuel costs.[104]

We decline to impose a requirement that "minimum take" constraints be prohibited for modeling dispatch in instances where there is no Commission-approved contract. No compelling evidence has been presented to demonstrate that this would be the appropriate default modeling approach in such instances. While we do not impose such a requirement here, we reiterate that it is PacifiCorp's obligation to present evidence in each ECAC proceeding of the reasonableness of its fuel costs, inclusive of estimated fuel costs. Based on this obligation, we expect that in future ECAC proceedings PacifiCorp will provide justification for why "minimum take" assumptions were or were not used.

6.3. Timing of Future Coal Supply Agreement Submission

As discussed above, D.21-11-001 requires PacifiCorp to analyze the prudence of all new coal supply agreements compared to alternative resources and to provide that analysis as part of the ECAC application where the costs of the coal supply agreements are proposed for inclusion in rates.[105] PacifiCorp will submit the coal supply agreements it executed during the pendency of this proceeding in its 2023 ECAC application. PacifiCorp states that requesting cost recovery in the 2023 ECAC is appropriate and affords parties sufficient opportunity to review the contracts while avoiding the potential for delays to this proceeding that could come from submitting a coal supply agreement mid-proceeding.[106]

---

[104] PacifiCorp Reply Brief at 13.

[105] D.21-11-001 at Ordering Paragraphs 4-5.

[106] PacifiCorp Opening Brief at 8-10.

While Sierra Club does not raise issue with PacifiCorp's approach, we take the opportunity to clarify the timing requirements from D.21-11-001. We clarify that for any coal supply agreements executed following the issuance date of this decision, PacifiCorp shall submit the coal supply agreement and the alternatives analysis required by D.21-11-001 in the first ECAC application filed after the coal supply agreement is executed. Ratepayer interests are best served by annual ECAC proceedings being resolved in a timely manner and by ensuring intervenors have sufficient time to review the prudency of new coal supply agreements. Both of these outcomes are more likely to be achieved if coal supply agreements executed during the pendency of a proceeding are submitted for review in the first ECAC application after the coal supply agreements are executed.

We also reiterate here the information PacifiCorp is required to provide when submitting new or renewed coal supply agreements to the Commission: Testimony shall address the generation forecast used to negotiate the new coal supply agreement;[107] whether the contract includes a minimum take provision, and if so, a comparison of the volume of the minimum take provision to the forecast generation at the associated coal generation plant;[108] a general description of how the coal contract compares with any previous coal supply contract(s) being replaced;[109] and analysis of the prudence of the agreement compared to alternative resources taking into account system-wide reliability

[107] D.20-12-004 at 25.

[108] *Ibid.*

[109] *Ibid.*

risk and all costs, under a variety of demand scenarios and without "must run" constraints.[110]

6.4. Comparison of "Minimum Take"/"Fixed Production Costs" to Forecast and Actual Plant Generation

As discussed earlier in this decision, one of the potential indicators of whether a coal plant is being dispatched economically is whether its forecast and actual generation levels are above the "minimum take"/"fixed production cost" constraints assumed in the dispatch model. In order to facilitate comparison of "minimum take"/"fixed production cost" constraints with forecast and actual generation levels, we require PacifiCorp to submit the following information for each coal plant as part of its annual ECAC filings:

- "Minimum take" or "fixed production cost" volume used in the NPC model for the current ECAC cycle year for each fuel source supplying the coal plant;
- Forecast generation volume for the coal plant for the current ECAC cycle year;
- "Minimum take" or "fixed production cost" volume used in the NPC model for the three prior ECAC cycle years for each fuel source supplying the coal plant;
- Actual generation volume for the coal plant for the three prior ECAC cycle years.

PacifiCorp shall supplement its 2023 ECAC filing with the requested information within 30 days of the issuance date of this decision.

7. Request for Waiver of Certain Modeling Requirements from D.20-12-004

As part of its 2022 ECAC application, PacifiCorp requested a waiver from its obligation to meet certain requirements imposed by D.20-12-004, arguing that

---

110 D.21-11-001 at Ordering Paragraphs 4-5.

its transition from the GRID production cost model to the Aurora production cost model for the 2022 ECAC obviates the need for those requirements.[111] D.20-12-004 requires PacifiCorp to provide:

1. Information on the marginal fuel cost assumed for each coal plant, the specific coal plants where adjustments were made to align forecasted generation with minimum take provisions, and the magnitude of adjustments made;
2. A GRID model run that depicts the NPC when adjustments are made to the Dispatch Tier to meet minimum take provisions;
3. A GRID model run that depicts the NPC when the Dispatch Tier is based purely on marginal costs; and
4. A GRID model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch.[112]

On November 30, 2021, Sierra Club filed a response opposing PacifiCorp's request for waiver of these requirements and arguing supplemental modeling is needed to understand whether "minimum take" requirements are driving generation at plants.[113]

An ALJ ruling was issued on December 21, 2021, granting PacifiCorp's request for waiver with modification. The ALJ ruling granted a waiver from the second and third modeling requirements only, finding that the transition to Aurora has made those modeling requirements moot and that there was not sufficient showing by parties to justify waiver from the first and fourth modeling requirements.

---

[111] PacifiCorp Application at 2.

[112] D.20-12-004 at 16-17.

[113] Sierra Club response to PacifiCorp's waiver request, November 30, 2021, at 5.

This decision affirms the ALJ ruling and clarifies that the conclusions reached in the ruling apply to this ECAC cycle as well as future ECAC cycles. We therefore find that beginning with the 2022 ECAC cycle, the following modeling requirements from D.20-12-004 are no longer required:

- A GRID model run that depicts the NPC when adjustments are made to the Dispatch Tier to meet minimum take provisions.
- A GRID model run that depicts the NPC when the Dispatch Tier is based purely on marginal costs.

In addition, we find that the following requirement from D.20-12-004:

- A GRID model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch.

Shall be modified to read:

- An Aurora model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch.

8. ECAC Rate Spread and Rate Design

All parties have stipulated to approval of PacifiCorp's recommended rate spread and rate design.[114] PacifiCorp has met its burden of proof in this proceeding and we find PacifiCorp's requested adjustment to its ECAC rates reasonable. We also find the proposed ECAC rate spread and rate design is consistent with the methodology first implemented in PacifiCorp's 2005 general rate case (GRC) and used in previous ECAC filings. Therefore, PacifiCorp's requested Balancing Rate of $4.25 per MWh is adopted and PacifiCorp's requested Offset Rate of $25.15 per MWh is adopted. The total ECAC rate increase of approximately $3.4 million is approved.

[114] Joint Status Conference Statement at 3.

9. Comments on Proposed Decision

The proposed decision of ALJ Shannon O'Rourke in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

10. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Shannon O'Rourke is the assigned ALJ in this proceeding.

Findings of Fact

1. The Commission previously authorized PacifiCorp to use the ECAC to recover its NPC and ARB implementation fees and mandatory reporting and verification costs.
2. The Balancing Rate and the Offset Rate comprise the two rate components of the ECAC.
3. PacifiCorp's current Balancing Rate is $1.05 per MWh.
4. PacifiCorp's requested 2022 Balancing Rate is $4.25 per MWh.
5. The difference between PacifiCorp's current Balancing Rate and the requested Balancing Rate exceeds five percent.
6. PacifiCorp's current Offset Rate is $23.88 per MWh.
7. PacifiCorp's requested 2022 Offset Rate is $25.15 per MWh.
8. The difference between PacifiCorp's current Offset Rate and the requested Offset Rate exceeds five percent.
9. The Commission adopted PacifiCorp's GHG-related costs and Climate Credits in this proceeding in D.22-03-014.

10. The combined requested ECAC and GHG rate modifications result in a rate increase of approximately $6,685,000, or 6.6 percent overall, for PacifiCorp's California retail customers.

11. The components of PacifiCorp’s proposed Balancing Rate are uncontested and are adequately supported by testimony and exhibits.

12. The components of PacifiCorp’s proposed Offset Rate other than the forecast fuel costs for the Jim Bridger plant are uncontested and are adequately supported by testimony and exhibits.

13. PacifiCorp’s coal supply agreement with the Black Butte mine expired in April 2022, which was during the pendency of this proceeding.

14. PacifiCorp had not renegotiated a coal supply agreement with the Black Butte mine at the time it filed its 2022 ECAC application.

15. PacifiCorp used a “proxy fuel cost” estimate for the Black Butte mine for the period after the existing coal supply agreement expired for NPC modeling purposes.

16. PacifiCorp is not required to conduct an alternatives analysis for “proxy fuel cost” estimates.

17. PacifiCorp used a reasonable approach for estimating fuel volumes for the Black Butte mine, including “minimum takes,” and fuel prices given the timing of the coal supply agreement expiration and the filing of the 2022 ECAC application, and its history with the mine.

18. Because the overall forecast generation for Jim Bridger is higher than the combined “minimum take” and “fixed production cost” obligations for Black Butte and BCC, it cannot be concluded that “minimum take” requirements were driving generation at the plant.

19. Forecast fuel costs from the BCC mine are based on an annual mine operating plan.

20. Volume and cost per ton of BCC coal supplies are similar to those approved in the two previous ECAC proceedings.

21. Sierra Club has not identified any specific costs in the BCC mine plan that are unreasonable.

22. It is reasonable to expect that certain costs at the BCC mine would be fixed over the short-term for modeling purposes.

23. Because the overall forecast generation for Jim Bridger is higher than the combined "minimum take" and "fixed production cost" obligations for Black Butte and BCC, it cannot be concluded that "fixed production costs" were driving generation at the plant.

24. The incremental cost of production is the cost to supply one additional MWh of generation.

25. The average cost of production is the ratio of the total cost of production to the total energy produced.

26. The use of incremental cost to inform short-term dispatch decisions is considered standard practice.

27. It was reasonable for PacifiCorp to assume certain fuel production costs were fixed over the one-year planning horizon of the ECAC.

28. The Jim Bridger Long-Term Fuel Supply Plan provides more flexibility to consider alternative resources than the annual mine operating plan because it considers a multi-year horizon rather than the one-year horizon of the annual mine plan.

29. Updating the Jim Bridger Long-Term Fuel Supply Plan for the 2024 ECAC will align with PacifiCorp's planned update for the 2023 Integrated Resource

Plan and provide sufficient time for it to inform PacifiCorp's 2024 ECAC application.

30. Economic cycling is the practice of taking a coal plant offline for a period of time and replacing it with other resources for the purposes of avoiding fuel costs.

31. As PacifiCorp's portfolio evolves, renewable resources increase, and coal plants near retirement dates, the notion that coal plants "must run" in perpetuity cannot be assumed.

32. A more nuanced analysis of how economic cycling of PacifiCorp's coal units could be deployed will inform understanding of whether economic cycling could be beneficial for customers in certain instances.

33. Although Sierra Club's proposed categories for the economic cycling analysis are appropriate, they would benefit from further refinement.

34. The timing requirement from D.21-11-001 to file new coal supply agreements and accompanying analysis is ambiguous.

35. Ratepayer interests are best served by annual ECAC proceedings being resolved in a timely manner and by ensuring intervenors have sufficient time to review the prudency of new coal supply agreements.

36. One of the potential indicators of whether a coal plant is being dispatched economically is whether its forecast and actual generation levels are above the "minimum take"/"fixed production cost" constraints assumed in the dispatch model.

37. An ALJ ruling was issued December 21, 2021 granting PacifiCorp's request for waiver from certain requirements in D.21-11-001 with modification.

38. All parties stipulated to approval of PacifiCorp's recommended rate spread and rate design.

Conclusions of Law

1. The appropriate standard of proof in a ratesetting proceeding is the "preponderance of the evidence" standard.

2. PacifiCorp's requested 2022 Balancing Rate of $4.25 per MWh is reasonable and should be approved.

3. PacifiCorp's approach to estimating "proxy fuel costs" for the Black Butte mine is reasonable.

4. PacifiCorp's approach to estimating forecast fuel costs for the BCC mine is reasonable.

5. PacifiCorp's use of incremental costs for forecasting coal generation dispatch is reasonable.

6. PacifiCorp's requested 2022 Offset Rate of $25.15 per MWh is reasonable and should be approved.

7. PacifiCorp should update its Jim Bridger Long-Term Fuel Supply Plan for its 2024 ECAC application.

8. The updated Jim Bridger Long-Term Fuel Supply Plan should at a minimum consider the long-term fueling options for Jim Bridger, including alternative fueling options for Units 3 and 4, and whether the plant could be retired early or have its generation reduced through displacement by alternative resources. The updated plan should also include an informational scenario that utilizes average cost dispatch.

9. PacifiCorp should conduct an economic cycling analysis and consult with interested parties on the scenarios that should be modeled.

10. It should be clarified that for any coal supply agreements executed after the issuance date of this decision, PacifiCorp should submit the coal supply

agreement and the alternatives analysis required by D.21-11-001 in the first ECAC application filed after the coal supply agreement is executed.

11. To facilitate comparison of "minimum take"/"fixed production cost" constraints with forecast and actual generation levels, PacifiCorp should be required to submit relevant information for each coal plant.

12. The December 21, 2021 ALJ ruling waiving certain requirements from D.20-12-004 should be affirmed and the conclusions reached in the ruling should apply to the 2022 ECAC cycle as well as future ECAC cycles.

13. PacifiCorp's recommended rate spread and rate design are reasonable and should be approved.

O R D E R

IT IS ORDERED that:

1. Within five days of the issuance date of this decision, PacifiCorp d/b/a Pacific Power shall file a Tier 1 Advice Letter with tariffs to implement the rate adjustments authorized by this decision.

2. PacifiCorp d/b/a Pacific Power shall update its Jim Bridger Long-Term Fuel Supply Plan (plan) and submit the plan as part of its 2024 Energy Cost Adjustment Clause application. The updated plan shall at a minimum consider the long-term fueling options for the Jim Bridger power plant, including alternative fueling options for Units 3 and 4, and whether the plant could be retired early or have its generation reduced through displacement by alternative resources. The updated plan shall also include an informational scenario that utilizes average cost dispatch.

3. Within 60 days of the issuance date of this decision, PacifiCorp d/b/a Pacific Power shall file and serve supplemental testimony in Application 22-08-001 with the results of a study that analyzes the benefits of economic cycling,

including limiting economic cycling to particular coal units, times of year, and/or the lengths of time that a unit would be offline.

4. To further refine the proposed categories for the economic cycling analysis referred to in Ordering Paragraph 3, PacifiCorp d/b/a Pacific Power, shall, within seven days of the issuance date of this decision, notify the service list of this proceeding and Application 22-08-001 of its intention to convene a meeting to receive input on scenarios for the study ordered by Ordering Paragraph 3 and shortly thereafter convene a meeting to receive input.

5. PacifiCorp d/b/a Pacific Power (PacifiCorp) shall update the study ordered by Ordering Paragraph 3 on an annual basis and submit the results of the study in its Energy Cost Adjustment Clause (ECAC) application annually. For these updates, PacifiCorp shall seek input from interested parties on scenarios before conducting the updates by notifying the service list of the most recently opened ECAC proceeding. PacifiCorp shall also detail its scenario refinements, input from stakeholders, and study results in its annual ECAC application.

6. For any of its coal supply agreements executed following the issuance date of this decision, PacifiCorp d/b/a Pacific Power shall submit the coal supply agreement and the alternatives analysis required by Decision 21-11-001 in the first Energy Cost Adjustment Clause application filed after the coal supply agreement is executed.

7. Within 30 days of the issuance date of this decision, PacifiCorp d/b/a Pacific Power shall file and serve supplemental testimony in Application 22-08-001 with the following information for each coal plant in its fleet, and shall include this information in each subsequent Energy Cost Adjustment Clause (ECAC) application it files:

a. "Minimum take" or "fixed production cost" volume used in the net power cost (NPC) model for the current ECAC cycle year for each fuel source supplying the coal plant;

b. Forecast generation volume for the coal plant for the current ECAC cycle year;

c. "Minimum take" or "fixed production cost" volume used in the NPC model for the three prior ECAC cycle years for each fuel source supplying the coal plant;

d. Actual generation volume for the coal plant for the three prior ECAC cycle years.

8. The December 21, 2021 Administrative Law Judge ruling waiving certain requirements from Decision 20-12-004 with modification is affirmed. For future Energy Cost Adjustment Clause (ECAC) cycles, the following adjustments are made to the requirements from Decision 20-12-004.

a. The requirements: "A GRID model run that depicts the NPC [net power cost] when adjustments are made to the Dispatch Tier to meet minimum take provisions." and "A GRID model run that depicts the NPC when the Dispatch Tier is based purely on marginal costs." are removed.

b. The requirement: "A GRID model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch." is modified to read "An Aurora model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch."

9. Application 21-08-004 is closed.

This order is effective today.

Dated ____________________________, at Chico, California