Docket No. UE 420

Exhibit SC/100

Witnesses: Ed Burgess and Maria Roumpani

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2024 Transition Adjustment Mechanism	Docket UE 420

Opening Testimony of Ed Burgess and Maria Roumpani

On Behalf of

Sierra Club

Public Version

June 23, 2023

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1. Summary of Findings and Recommendations

Q. Please provide a summary of your testimony.

A. Our testimony examines the coal fuel expenditures PacifiCorp proposes to recover through its 2024 Transition Adjustment Mechanism ("TAM"). We also discuss PacifiCorp's planned participation in the Extended Day Ahead Market ("EDAM") and its implications for future operation of the Company's coal fleet.

Q. Please provide a summary of your findings.

A. Our findings can be summarized as follows:

1. PacifiCorp's projected 2024 Net Power Costs ("NPC") includes approximately $[redacted] (system allocated) in fuel costs associated with future coal supply agreements ("CSAs") that have not been executed and are speculative in nature. Out of the $[redacted], $[redacted] are included based on a future CSA with Black Butte (for the Jim Bridger plant) [redacted]

2. PacifiCorp's projected 2024 NPC includes approximately $[redacted] in fuel costs associated with new or amended coal supply agreements with minimum take requirements and $[redacted] that have not been reviewed by the Commission. Even though these agreements have not been approved, PacifiCorp inappropriately treats these as fixed costs in the TAM modeling.

3. The 2024 TAM includes generation from Jim Bridger and recovery of the associated costs that do not align with any of the scenarios examined by PacifiCorp in its 2023 Long-Term Fuel Supply Plan ("LTFSP" or "Plan").

4. PacifiCorp's 2023 Jim Bridger Long-Term Fuel Supply Plan has numerous methodological flaws that severely limit its ability to identify a prudent course of action for the Jim Bridger plant's 2024 fuel supplies.

5. After correcting for the methodological flaws noted above, Scenario 4 of the LTFSP, which includes [redacted], appears to be the most beneficial for the Company's ratepayers.

6. PacifiCorp executed the new Gentry CSA before assessing other bids to its 2022 Request for Proposals ("RFP") [redacted]

7. PacifiCorp's average cost run results in a generation schedule that is counterintuitive and raises questions about the robustness of the analysis.

Q. Please provide a summary of your recommendations.

A. Our recommendations are:

1. The Commission should exclude from the 2024 TAM recovery of $[redacted] Oregon allocated) associated with an assumed Black Butte contract currently included in PacifiCorp's forecasted 2024 NPC.

2. Total coal supply and associated fuel costs for the Jim Bridger plant in the 2024 TAM should be limited to the volume and cost identified in Scenario 4 of the LTFSP.

3. The Commission should require PacifiCorp to submit an updated NPC analysis, excluding coal supply and associated costs from Black Butte for the Jim Bridger plant and limiting coal supply from Bridger Coal to Scenario 4 estimates.

4. The Commission should require PacifiCorp to revise its 2023 LTFSP consistent with the concerns discussed in Section 5 of our testimony. Moving forward, PacifiCorp should be directed to update its LTFSP every year.

5. The Commission should exclude coal fuel costs associated with the Hunter plant's Gentry CSA, totaling $[redacted] Oregon allocated).

6. The Commission should host one or more stakeholder workshops to discuss best practices for utility participation in wholesale markets (e.g. EDAM), and the role of future TAM proceedings in providing appropriate oversight of this participation.

7. Now that PacifiCorp has the modeling capabilities to assume different prices in AURORA, the informational run that assumes average cost for all coal units should be replaced with a run that assumes full cost of each contract/tier.

2. Introduction

Q. Please state your name, title, and business address.

A. **Burgess:** My name is Ed Burgess. I am a Partner at Strategen Consulting. My business address is 10265 Rockingham Drive, Suite 100-4061, Sacramento, California 95827.

Roumpani: My name is Maria Roumpani. I am a Technical Director at Strategen Consulting. My business address is 10265 Rockingham Drive, Suite 100-4061, Sacramento, California 95827.

Q. Please summarize your professional and educational background.

A. **Burgess:** I am a partner on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to resource planning, transmission planning, renewable energy, energy storage, utility rate design and program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full curriculum vitae is attached as Exhibit SC/101.

Roumpani: I am a Technical Director at Strategen and oversee much of the firm's mathematical modeling and quantitative analysis projects. At Strategen, I lead economic and technical grid modeling engagements, including capacity expansion, production cost, and energy storage dispatch modeling for government clients, non-governmental organizations, and trade associations. I have a PhD from the Management Science and Engineering Department at Stanford University and a Master of Science in Electrical and

Computer Engineering from the National Technical University of Athens, Greece. A full curriculum vitae is attached as Exhibit SC/102.

Q. On whose behalf are you testifying?

A. We are testifying on behalf of the Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to 1) provide an examination of PacifiCorp's TAM as it relates to coal fuel burn expenditures, 2) examine PacifiCorp's justification for assumed fueling costs from certain sources, and 3) provide recommendations on PacifiCorp's planned participation in the Extended Day Ahead Market ("EDAM"), and 4) provide recommendations on the "average cost" modeling run previously required by this Commission.

Q. Have you ever testified before this Commission?

A. **Burgess:** Yes. I testified in UE-375, UE-390, and UE-400, which were PacifiCorp's 2021, 2022, and 2023 TAM proceedings, respectively. I also testified in UG-435.

Roumpani: No, I have not.

Q. Are you generally familiar with electric utilities, and related policy and regulatory issues around the Western U.S.?

A. **Burgess:** Yes. I have participated in a variety of activities, projects, and policy forums related to the power system in the West. To provide a few recent examples, I have conducted multiple research projects for the Western Interstate Energy Board. I have participated in technical stakeholder processes at the Western Electricity Coordinating Council and WestConnect. I helped the State of Arizona complete a technical assessment (including power system modeling) of U.S. Environmental Protection Agency's Clean Power Plan. I have also engaged in several resource planning and grid modeling activities in Arizona, Nevada, and Colorado. For a recent client project, I conducted a detailed review and comparison of PacifiCorp's retail rate components across its six jurisdictions. I also testified before the Public Utilities Commission of California on PacifiCorp's proposed 2020, 2021, and 2022 Energy Costs Adjustment Clause ("ECAC") proceedings, which are the California equivalent of the TAM.

Roumpani: Yes. Similar to Mr. Burgess, I have participated in a variety of activities, projects, and policy forums related to the power system in the West. I have engaged in several resource planning and grid modeling activities in Arizona, Oregon, Utah, Washington, and Colorado. On behalf of clients, I have recently reviewed and in some cases conducted modeling for resource planning efforts for utility systems including Arizona Public Service, Idaho Power, PacifiCorp, Public Service Company of Colorado, Salt River Project, Tucson Electric Power, and others.

Q. Have you ever testified before any other state regulatory body?

A. **Burgess:** Yes. I have testified before the California Public Utilities Commission (Docket Nos. A.19-08-002, A.20-08-002, R.20-11-003, A.21-08-004, A.21-10-010, and A.21-10-011), the Colorado Public Utilities Commission (Docket No. 22A-0085E), the Indiana Utility Regulatory Commission (Cause Nos. 38707 FAC 123 S1 and 38707 FAC 125), the Louisiana Public Service Commission (Docket No. U-36105), the Massachusetts Department of Public Utilities (D.P.U. 18-150 and D.P.U. 17-140), the Michigan Public Service Commission (Docket No. U-21090), the Nevada Public Utilities Commission (Docket Nos. 20-07023 and 22-09006), the North Carolina Utilities Commission (Docket Nos. E-100, Sub 179 and E-2, Sub 1300) the South Carolina Public Service Commission (Docket Nos. 2019-186-E, 2019-185-E, 2019-184-E, and 2021-88-E), and the Washington Utilities and Transportation Commission (Docket Nos. UE-200900 and in UE-220053/UG-220054, UE-220066/UG-220067). Additionally, I have represented numerous clients by drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at utilities commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

Roumpani: Yes. I have testified before the Public Service Commission of South Carolina in Docket No. 2023-2-E regarding the Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc and provided written testimony in Docket No. 2023-1-E regarding the Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC. I have also testified before the Michigan Public Service Commission in the application of DTE Energy for the approval of its Integrated Resource Plan, before the North Carolina Utilities Commission in Duke Energy's application for approval of its Carbon Plan, and before the Colorado Public Utilities Commission in the Public Service Company of Colorado's application for approval of its 2021 Electric Resource Plan and Clean Energy Plan. Furthermore, I supported numerous Strategen clients by providing technical support for written testimony, drafting written comments, and participating in technical workshops on a range of proceedings in Arizona, California, Colorado, Kentucky, Michigan, Nevada, North Carolina, Oregon, and South Carolina.

Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

- Section 1 provides a summary of our findings and recommendations
- Section 2 provides a brief introduction;
- Section 3 provides an overview of the key features of PacifiCorp's proposed 2024 TAM, including new, amended and future CSAs in this proceeding;
- Section 4 discusses the prudency of PacifiCorp's proposed fuel costs for the Jim Bridger plant
- Section 5 discusses our concerns with the 2023 Jim Bridger Long Term Fuel Supply Plan;
- Section 6 discusses the prudency of PacifiCorp's proposed Hunter plant CSAs;
- Section 7 discusses PacifiCorp's planned participation in the EDAM; and
- Section 8 discusses the "average cost" AURORA model run completed in the 2024 TAM.

3. <u>The Transition Adjustment Mechanisms and PacifiCorp's 2024 TAM Application</u>

A. <u>Overview of the 2024 TAM</u>

Q. What is the purpose of the Transition Adjustment Mechanism?

A. The TAM is a rate adjustment that PacifiCorp files annually to update its forecasted NPC calculation. The NPC is in turn used to determine the power supply rates for customers who have elected to take cost-based supply service (e.g., under Rate Schedule 201).

These rates recover costs primarily related to the fuel and purchased power costs associated with power generated or procured to serve PacifiCorp's customers.

Q. What is the significance of the TAM for a typical residential customer's bill?

A. In PacifiCorp's case, fuel costs are on the order of 3.3-4.3¢/kWh,[1] or roughly 28-35% percent of standard residential energy rates.[2] Given the impact on captive customers' bills, proceedings like this one are very important for customers.

Q. Please provide a brief overview of PacifiCorp's application for approval of its 2024 TAM.

A. On April 3, 2023, PacifiCorp submitted an application to this Commission requesting authorization to update certain components of its TAM for 2024. As required by the 2023 TAM Order, PacifiCorp filed an updated Long-Term Fuel Supply Plan for the Jim Bridger coal plant on May 31, 2023 and an analysis of the CSAs for Hunter, Wyodak, and Dave Johnston.

Q. Please provide a brief overview of what costs are included in the NPC.

A. NPC represents the power costs of meeting PacifiCorp's total generation requirements (including both retail load and sales for resale). More specifically, NPC is defined as the sum of fuel expenses, wholesale power purchase expenses and wheeling expenses, less wholesale sales revenue.

Q. Have you reviewed PacifiCorp's testimony and supporting workpapers in this proceeding regarding the calculation of the 2024 TAM?

A. Yes. We reviewed the testimony and supporting workpapers. The primary component of the 2024 TAM is PacifiCorp's forecasted NPC for the year 2024, a portion of which is allocated to Oregon.

Q. What is the total-company NPC in the TAM for calendar year 2024?

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[1] Ex. Accompanying Direct Test. of Judith M. Ridenour Proposed TAM Rate Spread and Rates [hereinafter "PAC/301"].

[2] Assuming 12 ¢/kWh for baseline PacifiCorp's residential energy charges.

A. The forecasted normalized total-company NPC for calendar year 2024 is $2.642 billion.[3] This is approximately $665 million higher than the total-company forecast NPC of approximately $1.977 billion in the 2023 TAM. Approximately 28.6 percent of the forecasted NPC, or $756 million (increase of $255 million), is allocated to Oregon.[4]

Q. What adjustments are made to NPC for the purpose of setting the 2024 TAM power supply rates?

A. The largest adjustment is the subtraction of the Production Tax Credit ("PTC"), which totals $280 million for 2024, or $80.4 million for Oregon. Additional Oregon Situs NPC adjustments result in a $0.9 million reduction. The Total TAM net of adjustments for Oregon is $674 million. Furthermore, there is a change due to load variation from UE-400 of $83.5 million.

Q. Can you summarize the underlying components of the NPC in the 2024 TAM?

A. Yes. The main components of the total NPC are summarized in the following table, based on Exhibit PAC/101.

[3] Ex. Accompanying Direct Test. of Ramon J. Mitchell Oregon-Allocated Net Power Costs at Mitchell/1:1-35 [hereinafter "PAC/101"].
[4] *Id.*

Table 1: 2024 NPC Components

Category	**Total Company (million)[5]**	**Oregon allocated (million)[6]**
Sales for resale	$426	$122
Purchased power	$1,494	$429
Wheeling expense	$166	$48
Fuel expense	$1,409	$402
Coal Fuel Burn expenses	*$547*	*$156*
Gas/Other Fuel Burn expenses	*$861*	*$246*
Net power cost (per Aurora)	$2,642	$756
Oregon situs NPC adjustments	$(0.91)	$(0.91)
Total NPC	$2,642	$755

As the table above shows, $547 million of fuel costs are for coal fuel expenses. Thus, nearly 21 percent of the NPC is comprised of costs for burning coal.

B. <u>Cost of Coal Fuel Included in the 2024 TAM</u>

Q. Can you provide a breakdown of the coal fuel burn expenses that are included in the 2024 NPC Projections?

A. Yes. The anticipated 2024 coal fuel burn expenses can be broken down by plant as follows:

[5] PAC/101 at Mitchell/1:1-38.
[6] *Id.*

Confidential Table 2: Unit Average Cost Based on 2024 Projected NPC and Generation

Plant	2024 Projected Coal Burn Expenses ($)[7]	2024 Projected Generation (MWh)[8]	Average Cost ($/MWh)[9]
Cholla			
Colstrip	19,942,369	[redacted]	
Craig	19,546,377	[redacted]	
Dave Johnston	45,234,123	[redacted]	
Hayden	11,875,630	[redacted]	
Hunter	167,870,240	[redacted]	
Huntington	76,807,787	[redacted]	
Jim Bridger	157,086,494	[redacted]	
Naughton	31,553,788	[redacted]	
Wyodak	17,471,353	[redacted]	
Total	547,388,163	[redacted]	

Q. What do you conclude from this information?

A. Across PacifiCorp's coal fleet, there is a significant range in coal fuel related costs projected for 2024. On average, the NPC for all of PacifiCorp's coal plants is expected to be $[redacted]MWh. However, for some plants the cost is much higher. For example, the Jim Bridger and Hunter plants have projected coal fuel burn expenses of $[redacted]MWh and $[redacted]/MWh, respectively. Sierra Club has pointed out that Jim Bridger has been one of the Company's most expensive coal plants in each of the last three TAM proceedings.

Q. Do these costs, recovered through the TAM, include all of the anticipated costs to continue operating these coal plants?

A. No. Some of the ongoing costs may be recovered as capital expenditures. For example, there are other ongoing costs associated with those plants that are not recovered through

[7] Ex. Accompanying Direct Test. of Ramon J. Mitchell, Net Power Costs Report at Mitchell/4 [hereinafter "PAC/102"]

[8] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24_Mitchell Direct Mar 2023 CONF" at 'NPC' tab.

[9] *Id.*

the TAM, such as operations and maintenance costs. Additionally, PacifiCorp owns the Bridger Coal Company ("BCC" or "Bridger Mine"), and some of the fixed costs associated with the mine are included in the Company's rate base rather than through adjusters like the TAM.

Q. How does the coal fuel burn expense projected in the 2024 TAM differ from the 2023 TAM projection?

A. PacifiCorp's projected coal fuel expense is $91.5 million lower, or 14 percent less, than the 2023 TAM Reply forecast.[10] This decrease is attributed to PacifiCorp's lower coal consumption. However, coal prices are projected to be 30% higher on a $/MWh basis. Interestingly, Jim Bridger's fuel costs, which have historically been among the Company's most expensive, seem to have experienced [redacted] Meanwhile, [redacted] shows the highest increase with the [redacted] as compared to 2023. For the Jim Bridger plant, the Bridger Coal Company supply is [redacted] more expensive than in 2023 and the Black Butte supply is [redacted] more expensive. All other coal supply is projected to experience increases below [redacted]

Confidential Table 3: Cost Comparison by Coal Source ($/Ton)[11]

Plant	**Supplier**	**2024 TAM Direct**	**2023 TAM Reply**	**Variance %**
Colstrip	Westmoreland/Rosebud	[redacted]	[redacted]	[redacted]
Craig	Trapper Mining Inc	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody/NARM	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody/Caballo	[redacted]	[redacted]	[redacted]
Dave Johnston	Unspecified PRB Mines	[redacted]	[redacted]	[redacted]
Dave Johnston	Eagle Butte	[redacted]	[redacted]	[redacted]
Hayden	Peabody/Twentymile	[redacted]	[redacted]	[redacted]

[10] Confidential Direct Test. of James Owen at Owen/24:4 [hereinafter "PAC/200"].
[11] *Id.* at Owen/23:5.

Hunter	Wolverine/Various	[redacted]
Hunter	Bronco/Emery	
Hunter	Gentry Mountain	
Huntington	Wolverine/Various	
Jim Bridger	Lighthouse Resources/Black Butte	
Jim Bridger	Bridger Coal Company	
Naughton	Kemmerer Operations	
Wyodak	Black Hills/Wyodak	

C. New, Amended, and Future CSAs in the 2024 TAM

Q. Has PacifiCorp entered into any new CSAs since it filed reply testimony in the 2023 TAM?

A. Yes. According to Mr. Owen's Direct Testimony, "PacifiCorp has entered into new CSAs [(as opposed to amendments to current CSAs)] for the Wyodak plant (Wyodak CSA), for the Dave Johnston plant (Eagle Butte CSA), and for the Hunter plant (Gentry CSA). In addition, amendments have been signed for the Dave Johnston plant Caballo CSA (Caballo CSA) and for the Hunter plant (Bronco CSA)."[12]

Q. Is PacifiCorp assuming any future contracts in its forecast for 2024?

A. Yes. PacifiCorp is assuming the execution of a new CSA with Black Butte for the Jim Bridger plant, as well as the execution of a contract with [redacted] for the Hunter plant, and finally supply from unspecified Powder River Basin mines for the Dave Johnston plant.

Q. Do any of these new, amended, or future CSAs include minimum take provisions for 2024?

A. Yes. For the [redacted] of the

[12] PAC/200 at Owen/11:15-19.

forecasted deliveries for [redacted] in 2024.[13] For the Hunter plant, the new Gentry CSA is assumed to have a minimum take requirement, [14] [redacted] in PacifiCorp's analysis.[15] The Black Butte CSA for Jim Bridger is also assumed to be subject to a minimum take.[16,17]

Q. Can you elaborate on how assuming a minimum take provision impacts the Company's NPC forecast?

A. Yes. In its generation dispatch modeling (using the AURORA software platform) PacifiCorp sets a price of zero for any coal volume that is subject to a minimum take provision.[18] Theoretically, this could be justified for existing contracts which had been subject to a prudency review at the time they were signed. However, the assumption of zero marginal cost allows the model to dispatch the Company's fleet such that coal would be purchased regardless of usage is prioritized over other fuels. Thus, ratepayers cover those coal fuel expenses even if they are higher than potential alternatives at the time of generation, because PacifiCorp is subject to the take or pay provision.

In this case, the Company has chosen to model several recently executed and speculative future contracts with a minimum take provision, even though such provisions are not yet in place or have not been reviewed by the Commission. Furthermore, PacifiCorp inappropriately models supply from the Bridger Coal Company, which is an affiliate mine, as subject to a minimum take provision.

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[13] Confidential Ex. Accompanying Direct Test. of James Owen CSA Contract Minimums Table at Owen/1 [hereinafter "PAC/205"].
[14] PAC/200 at Owen/15:15-17.
[15] PacifiCorp Response to Sierra Club Data Request 1.16(a). Public data responses from this proceeding referenced herein are compiled and attached as Ex. SC/103.
[16] PAC/200 at Owen/27:13
[17] PAC/205.
[18] PacifiCorp Response to Sierra Club Data Request 1.4(a) in Cal. Pub. Utils. Comm'n Proceeding No. A.21-08-004 (explaining that in AURORA, "[m]ust-take coal quantities are priced at "$0", and are included in the total fuel cost for each plant."). Public data responses from A.21-08-004 referenced herein are compiled and attached as Ex. SC/106.

Q. New or future CSAs could still be subject to minimum take requirements. Do you disagree?

A. Ideally, they would not. For example, the Wyodak CSA is not subject to annual minimum volume constraints.[19] [redacted][20] Still, we understand that some coal supply from third parties might require the inclusion of a minimum take provision as a practical matter. Our argument here, however, is not that the CSAs should not be subject to a minimum take provision, but that if those CSAs have not been executed or reviewed by the Commission, the Company should not model them with the minimum take provision in its forecast. Instead, the optimization model should decide how much to consume at the full price. If the model consumes less coal than the assumed minimum take quantity, this would indicate that the assumed minimum take is not economic. Consequently, entering into a CSA with that provision would be imprudent. This determination is not feasible when the Company includes the prospective CSAs as must-take in its modeling. In short, before any must-take quantity becomes fixed—that is, while it could still be reduced or eliminated—the Company should not assume that the minimum take will necessarily be recovered from ratepayers. In other words, prior to approval, the minimum take provisions (and associated costs) are not a *fait accompli* and could still be reconsidered and compared to potential alternatives.

Q. Has PacifiCorp produced analysis for the prudence of the new and amended CSAs?

A. Yes. As part of his testimony, Company witness James Owen provided exhibits including the analysis for each of the new contracts (Dave Johnston, Wyodak, Hunter). In addition to the new contracts, the Hunter analysis also reviews the Bronco amendment and provides information on an assumed future contract for the plant. No analysis has been produced for the Black Butte future contract, although the Company's Long-Term Fuel Plan for Jim Bridger assesses different scenarios including ones with supply from Black

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[19] PAC/200 at Owen/13:2.
[20] PAC/205.

Butte. [redacted][21]

Q. Do you have concerns about the analyses and the new fuel sources, including their cost and risk to customers?

A. Yes. Our concerns are focused on the coal supply for the Hunter and Jim Bridger plants. Coal supply for both plants became significantly more expensive and is assumed to be subject to take-or-pay provisions in the Company's modeling, even though the coal supplies for these two plants are comprised of new, amended or future contracts, or are not even subject to a contract as is the case of the Bridger Coal Company supply. We do not address the Wyodak or Dave Johnston contracts as the fuel costs for those plants remain low and [redacted]. We will explain our concerns about the Hunter and Jim Bridger fuel cost assumptions in the sections below.

4. **Jim Bridger Fuel Supply Costs in the 2024 TAM**

Q. Please explain your focus on the Jim Bridger fuel supply.

A. Not only is Jim Bridger the largest coal plant on the PacifiCorp system (2,120 MW, two thirds of which is owned by PacifiCorp) with the greatest generation output, but over the last several TAM cycles, it has consistently had one of the highest per unit ($/MWh) fuel costs of any coal plant in PacifiCorp's fleet. Additionally, between the 2023 and 2024 TAM, the projected $/MMBtu cost for Jim Bridger actually increased by [redacted] - even though the projected cost for all other coal units (excluding [redacted]) only increased by a maximum of [redacted]. The plant is supplied both from a third-party source (Black Butte mine) as well as an affiliate mine that is jointly owned by PacifiCorp and Idaho Power (Bridger Coal Company) and included in the Company's rate base. By comparison, coal prices for the Wyodak and Dave Johnston plants, whose previous CSAs also expired, [redacted] for the Craig plant, which is similarly supplied by an affiliate mine.

[21] PacifiCorp Highly Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant at 13 (May 31, 2023) [hereinafter "SC/107, Highly Confidential LTFSP"] (Attached as Ex. SC/107).

Q. Is PacifiCorp seeking to include fuel costs for the Jim Bridger coal plant in this year's 2024 TAM?

A. Yes. PacifiCorp's 2024 TAM application includes fuel costs for the Jim Bridger plant. These costs include assumed coal fuel deliveries from both the third-party owned Black Butte mine and the PacifiCorp-owned Bridger Coal Company mine.

Q. Did PacifiCorp provide the 2023 update to its Long-Term Fuel Supply Plan ("LTFSP" or "Plan") for the Jim Bridger Plant as part of its application in this case?

A. No. The 2023 LTFSP update had not been completed when PacifiCorp filed its 2024 TAM application on April 3, 2023. PacifiCorp completed the 2023 LTFSP update on May 31, 2023 and subsequently provided it to Sierra Club as a highly confidential response to a discovery request.

Q. Have you reviewed PacifiCorp's 2023 Highly Confidential LTFSP for the Jim Bridger Plant?

A. Yes.

Q. In PacifiCorp's 2024 TAM application, are the projected volumes and costs of coal fuel consumed at Jim Bridger consistent with any of the scenarios analyzed in the 2023 LTFSP update, including the Preferred Scenario?

A. No, they are not consistent. For instance, the 2024 TAM assumes [redacted], while the 2023 LTFSP Preferred Scenario [redacted]. There are other inconsistencies that we discuss in more detail throughout the remainder of this section.

Q. Can you summarize some of the key details of the 2023 LTFSP?

A. Yes. The 2023 Plan provides an analysis of six potential fueling scenarios for the Jim Bridger plant, from 2023 through 2029, when Units 3 and 4 are projected to convert to burning natural gas. Under Scenario 1, the plant is [redacted], under Scenario 2, the plant is [redacted], under Scenario 3, [redacted]

[redacted],[22] under Scenario 4, [redacted], and under Scenario 5 the plant is also [redacted] and under Scenario 6, the plant is [redacted], but assumes no minimum production requirement.[23] PacifiCorp concluded that Scenarios 5 and 6 were the least-cost, least-risk options. Despite the absence of a minimum production requirement in Scenario 6, the Company claims that PLEXOS selected all of the incremental coal from the Bridger mine as cost effective and thus Scenarios 5 and 6 are essentially the same. PacifiCorp refers to these scenarios collectively as the Preferred Scenario.

Q. Please summarize the key characteristics of PacifiCorp's Preferred Scenario in the LTFSP.

A. Under the Preferred Scenario the Jim Bridger plant is [redacted]

Q. Do any of the scenarios in the 2023 Jim Bridger LTFSP correspond to the fuel costs that PacifiCorp has included in the 2024 TAM?

A. No. The fuel assumptions for Jim Bridger in the [redacted]. However, none of the scenarios modeled in the LTFSP (including the Preferred Scenario) [redacted] Scenarios 1, 2, and 3 of the LTFSP [redacted], while Scenarios 4, 5, and 6 [redacted]. In other words, the fuel costs PacifiCorp included in its 2024

[22] SC/107, Highly Confidential LTFSP at 5.
[23] *Id.* at 12-13.

TAM application are not consistent with or informed by the most recent LTFSP for Jim Bridger.

Q. How do the 2024 TAM fuel costs for Jim Bridger compare to the fuel costs from the Preferred Scenario in the 2023 LTFSP?

A. The total volume of coal consumed in 2024 is somewhat similar between the two cases, though it is slightly lower in the 2024 TAM than in the 2023 LTFSP. However, the overall cost of the fuel in 2024 is actually *higher* in the 2024 TAM than in the LTFSP. Thus, if the Commission approved PacifiCorp's TAM application "as is," then customers would be paying at least $[redacted]Oregon allocated) more for coal fuel than what the Company's most recent analysis suggests is necessary or prudent.

Highly Confidential Table 4: Projected 2024 Coal Fuel Consumption at Jim Bridger

	2024 Projected Volume	2024 Projected Cost
TAM (2024 Application)	[redacted][24]	[redacted][25]
LTFSP Preferred Scenario (2023 Update)[26]	[redacted]	[redacted]

Q. Do you have a recommendation for the amount of coal that should be included in the 2024 TAM for Jim Bridger?

A. Yes. As we explain in the next section in detail, we find Scenario 4 to be a better fueling plan for Jim Bridger. Thus, we recommend that the fuel consumption for Jim Bridger in the 2024 TAM be limited to the volume identified in Scenario 4.

A. *Black Butte Fuel Costs Included in the 2024 TAM*

Q. Is PacifiCorp's application seeking cost recovery in the 2024 TAM for anticipated Black Butte costs under a future CSA?

A. Yes. PacifiCorp includes supply from Black Butte in its 2024 TAM. The Company, however, has only provided speculative information about future Black Butte fuel costs in its application for the Commission's review. These speculative Black Butte costs are

[24] PAC/205 at Owen/1, Confidential: Coal Supply Agreement Contract Minimums.
[25] Confidential Workpaper Supporting PacifiCorp's 2024 TAM Appl., "OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF," NPC Summary tab.
[26] SC/107, Highly Confidential LTFSP at App. 12.

embedded in PacifiCorp's projected 2024 NPC included in the TAM application. According to Confidential Table 6 in PAC/200, the Black Butte CSA will supply [redacted] tons at a price of [redacted], compared to a price of [redacted] in the 2023 TAM. In summary, PacifiCorp seeks to recover over $[redacted] Oregon allocated) in the 2024 TAM for coal fuel from Black Butte even though the Company provided no justification for this in its application.

Q. Did PacifiCorp provide any analysis supporting its estimate of the quantity and pricing for the Black Butte coal fuel that was included in the 2024 TAM?

A. Not to our knowledge. In its response to Sierra Club Request 1.19, PacifiCorp stated that "[p]ricing and volumes were based on conversations with the supplier, management's professional judgement, and estimates for the assumed contract volumes as shown in the work papers."[27] No supporting workpapers or analysis were provided to explain how this volume and pricing were estimated. The Company's workpapers included no contract analysis for Jim Bridger.

Q. Has PacifiCorp commented on the necessity of a Black Butte contract?

A. Witness Mr. Owen stated that the Jim Bridger inventory levels have declined since the latter half of 2022 and are projected to further decline below target levels intended to maintain availability at the plant.[28] According to Mr. Owen, "[w]ithout coal supplied by Black Butte in 2024, it would not be possible to restore inventory levels to prudent operating levels."[29] Similar arguments are also made in the conclusion of the Long-Term Fuel Supply Plan stating that PacifiCorp will have a limited ability to respond if generation needs increase at Jim Bridger or an unplanned production shortfall occurs at the Bridger mine.

Q. Do you share these concerns?

A. No, we do not. Redundancy always reduces certain risks but is not always the prudent option. [redacted], we believe that PacifiCorp should not enter into a contract at the expense of ratepayers.

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[27] SC/103, PacifiCorp Response to Sierra Club Data Request 1.19(f).
[28] PAC/200 at Owen/28:7-9.
[29] *Id.* at Owen/29:9-10.

Furthermore, because PacifiCorp owns the Bridger mine, it is possible that PacifiCorp could increase production at that mine if it determined doing so was necessary. Another alternative would be to increase supply from the Powder River Basin if either of the two risks that PacifiCorp identified materialize. Based on knowledge that PacifiCorp gained from consuming coal from the Powder River Basin at Jim Bridger in 2015 and on PacifiCorp's professional judgment, PacifiCorp believes that up to a total of 800,000 tons of Powder River Basin coal per year can be safely and reliably consumed without major modifications to the plant infrastructure.[30] Given that the Preferred Scenario includes consumption of [redacted] of the projected Bridger Coal Company supply.

Q. What is your recommendation regarding the speculative Black Butte CSA and the associated costs?

A. We recommend that the Commission disallow the $[redacted] Oregon allocated) included in PacifiCorp's 2024 TAM application for the speculative Black Butte CSA [redacted] and that the Commission require PacifiCorp to submit an updated NPC as soon as possible, ideally in its reply testimony, excluding the speculative CSA.

B. Bridger Coal Company Mine Fuel Costs Included in the 2024 TAM

Q. In addition to Black Butte, do you have any additional concerns regarding the recovery of Jim Bridger coal fuel costs in the 2024 TAM?

A. Yes. In addition to Black Butte, PacifiCorp is also seeking cost recovery for mining costs from BCC, which also supplies the Jim Bridger plant, without sufficiently justifying those costs. Because PacifiCorp, along with Idaho Power Company, co-owns the BCC mine, TAM-related costs are not based on a CSA *per se*, but rather on an annual operating plan that serves as the functional equivalent to a new CSA. Given that PacifiCorp has known about the high cost of coal at BCC in previous TAM cycles, it is particularly important for the Commission to exercise its authority to review the

[30] PacifiCorp Redacted Long-Term Fuel Supply Plan for the Jim Bridger Plant at 10 (May 31, 2023) [hereinafter "SC/108, Public LTFSP"] (Attached as Ex. SC/108).

reasonableness of BCC expenses. BCC coal has historically been one of the most expensive coal supply options for PacifiCorp. Moreover, annual cost increases at BCC far exceeded other suppliers [redacted]

Q. Do you recommend that PacifiCorp align the Bridger mine's production in the 2024 TAM with its LTFSP?

A. Yes. We recommend that PacifiCorp follows a fueling scenario close to the volume assumed in Scenario 4 of the LTFSP. If the Company's LTFSP analysis corrected for the methodological issues that we identify below in Section 5, we believe that Scenario 4 would be the most economic option for PacifiCorp customers.

Q. Does PacifiCorp have a disincentive to reduce coal volumes at BCC, even if doing so is in the best interest of its customers?

A. Yes. There are at least four reasons for such a disincentive. First, as explained earlier, the BCC mine is included in PacifiCorp's rate base for all its jurisdictions except California. Thus, an accelerated reduction or closure of the mine's output could jeopardize the authorized regulated rate of return PacifiCorp receives from this asset. Second, reduced volumes may put PacifiCorp at risk for not collecting sufficient revenue to support mine reclamation activities it is obligated to pursue.[31] Third, low generation output due to poor coal fuel economics could lead to additional pressure to retire the Jim Bridger plant early. This would eliminate future capital investment opportunities associated with the plant (e.g., unit overhauls). Fourth, the BCC mine is located in Wyoming which has a significant dependency on its coal economy. If PacifiCorp were to advance a plan to reduce or close the BCC mine, it could have negative repercussions for the Company among its Wyoming stakeholders.

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[31] Notably, PacifiCorp has not considered other options for collecting revenue for mine reclamation activities. *See* SC/106, PacifiCorp Response to Sierra Club Data Request 2.10 in A.21-08-004.

Q. What action do you recommend the Commission take regarding the estimated costs associated with the BCC 2024 Operating Plan, which have not been reviewed by the Commission?

A. We recommend that the Commission exclude the estimated Black Butte costs and allow cost recovery for Jim Bridger up to the fuel level and cost of Scenario 4.

Q. Why should the Commission approve costs for Scenario 4 instead of one of the other scenarios in the LTFSP (including PacifiCorp's Preferred Scenario)?

A. As mentioned above, we believe there are methodological deficiencies in the LTFSP that, if corrected, would lead Scenario 4 to be the least cost of the scenarios analyzed. Additionally, Scenario 4 [redacted] among the LTFSP scenarios. Thus, among the scenarios analyzed in the LTSFP, Scenario 4 does the best job of [redacted] Furthermore, as we also mentioned, there would still be sufficient flexibility to alter production at BCC or another source if necessary at a later date. If additional costs materialized, they could still be recovered by PacifiCorp through the PCAM.

5. Additional Methodological Concerns with PacifiCorp's Analysis for the 2023 Jim Bridger LTFSP

Q. Do you have concerns about the underlying analysis PacifiCorp performed in support of its 2023 LTFSP?

A. Yes. To be clear, our primary and overarching concerns relate to the discrepancies between PacifiCorp's 2023 LTFSP and the 2024 TAM as explained in the previous section. However, even if those concerns are addressed, we have several remaining concerns with the 2023 LTFSP analysis and the resulting Preferred Scenario. Specifically, these include the following:

- *BCC Cost Assumptions:* First, the fuel prices assumed, especially for the Bridger Coal Company fuel, lack support and are dramatically different across scenarios. Prices are also inconsistent with the current TAM filing.
- *2023 Costs in PVRR Calculation:* Second, the plan compares costs starting in 2023, even though 2023 is no longer relevant for planning purposes as PacifiCorp

seeks to find the optimal fueling strategy starting in 2024. Year 2023 alone creates differences of $[redacted] million PVRR between the Preferred Scenario and other scenarios. Including 2023 costs inappropriately inflates the stated benefits of the Preferred Scenario relative to the other scenarios as they are presented in the plan.

- *PLEXOS Model Assumptions:* Third, in this plan, PacifiCorp determines the Preferred Scenario by comparing the total present value revenue requirement ("PVRR") of each fueling option using major NPC components for the PacifiCorp system: fuel costs for all coal and gas plants along with purchase costs offset by power sales revenue.[32] This, although not incorrect in principle, leads to ranking fueling options largely based on an assumption around the system's ability to sell power, as we explain later in this section. It also creates some questions around the system assumptions that were used for these model runs, given that the 2024 TAM application was filed prior to the Company's proposed 2023 Integrated Resource Plan ("IRP").
- *Limited assessment of scenarios with an earlier closure for the Bridger coal mine:* Finally, while PacifiCorp modeled scenarios with closure of the Bridger coal mine in [redacted], they did not model a scenario that would keep operating the Bridger mine until 2025, and terminate the Black Butte supply at the end of 2023. Such a scenario would have been consistent with Sierra Club's recommendations in prior proceedings.

A. BCC Cost Assumptions

Q. Your first concern stem from the Company's coal pricing assumptions included in the 2023 LTFSP. Can you provide more information?

A. Yes. The pricing assumptions for the three coal sources supplying the Jim Bridger plant lack adequate support, are inconsistent with the 2024 TAM, and change dramatically and in unjustified ways between fueling scenarios.

For example, according to Appendices 8-13 of the Plan, Scenarios 1, 2, and 3 assume a BCC price of $[redacted]/ton for [redacted] million tons in 2023. Under Scenarios 4, 5, and 6, however, a BCC price of $[redacted] is assumed for [redacted] million tons. This more than [redacted]

[32] SC/108, Public LTFSP at 13.

costs for Scenarios 1, 2, and 3, while also [redacted] Even if we were to accept that [redacted], PacifiCorp's apparent assumption that [redacted] is simply unreasonable.

Highly Confidential Table 5: 2023 Coal Price Assumptions

		2023			
		S1, S2, S3[33]	S4[34]	S5, S6[35]	2023 TAM[36]
BCC	Tons (million)	[redacted]	[redacted]	[redacted]	[redacted]
	$/ton	[redacted]	[redacted]	[redacted]	[redacted]
	$ (millions)	[redacted]	[redacted]	[redacted]	[redacted]
BBC	Tons (millions)	[redacted]	[redacted]	[redacted]	[redacted]
	$/ton	[redacted]	[redacted]	[redacted]	[redacted]
	$ (millions)	[redacted]	[redacted]	[redacted]	[redacted]
PRB	Tons (millions)	[redacted]	[redacted]	[redacted]	[redacted]
	$/ton	[redacted]	[redacted]	[redacted]	[redacted]
	$ (millions)	[redacted]	[redacted]	[redacted]	[redacted]

Q. Did PacifiCorp provide any analysis supporting its estimate of the quantity and pricing for the Black Butte coal fuel examined in the LTFSP?

A. Not to our knowledge. No supporting workpapers or analysis were provided to explain how the volumes and pricing were estimated for the Black Butte fuel supply.

Q. Did PacifiCorp provide any analysis supporting its estimate of the quantity and pricing for the Bridger Coal Company coal fuel examined in the LTFSP?

A. According to PacifiCorp's response to Sierra Club Request 1.5, the "base delivered tons assumed for…BCC…is based on the estimated production level in the mine plan when

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[33] *Id.* at Apps. 8, 9, and 10
[34] *Id.* at App. 11
[35] *Id.* at Apps. 12 and 13
[36] PAC/200 at Owen/26:1 (Conf. Table 6).

operating one dragline."[37] The pricing is also based on a single dragline, as provided in Mr. Owen's confidential workpaper "01 OpsCostSchedules.xlsx." Although the BCC numbers (both total tonnage and pricing) for Scenarios 4, 5, and 6 are reasonably similar for year 2024 with the tonnage and pricing provided in Mr. Owen's confidential workpapers, they slightly deviate from the yearly mine plans (as outlined in the "01 OpsCostSchedules" workpaper) for later years.[38] The differences are not large but can amount to [redacted] and reduce any stated difference between the NPVRR of Scenario 4 and that of the Preferred Scenario. More importantly, no workpaper has been provided that explains how the coal volume was selected for each year in the fuel plan, as the base quantities fluctuate from year to year, and the prices differ in each file or workpaper provided, with the prices used to inform future years in the LTFSP being [redacted] in some cases even when the same coal volume was assumed.

[37] SC/103, PacifiCorp Response to Sierra Club Data Request 1.5.
[38] *Compare* Confidential Workpapers Accompanying the Direct Test. of James Owen, Incremental 1DL to 2DL Calcs (listing cost/ton for one dragline in 2024 as \$[redacted]/ton and for two draglines as \$[redacted]/ton) *with* SC/107, Highly Confidential LTFSP at App. 11 (listing the cost/ton in 2024 as \$[redacted] under Scenario 4 [redacted] *and* SC/107, Highly Confidential LTFSP at App. 12 (listing the cost/ton in 2024 as \$[redacted] under Scenario 5 [redacted] *and* SC/107, Highly Confidential LTFSP at App. 13 (listing the cost/ton in 2024 as \$[redacted] under Scenario 6 [redacted]); *see also* Highly Confidential Table 6.

Highly Confidential Table 6: Estimate of Quantity and Pricing for BCC

	2024	2025	2026	2027	2028
ONE DRAGLINE					
OPS WORKPAPER 1DL[39]					
TOTAL TONS DELIVERED	[redacted]				
COST PER TON ($/TON)	[redacted]				
Fuel Plan (Scenario 4)[40]					
Total Tons Delivered	[redacted]				
Cost Per Ton ($/ton)	[redacted]				
Two Draglines					
OPUC Compliance Filing Order No. 22-389 ("No minimum take" scenario) Bridger Coal Company - Hypothetical Fixed/Variable Cost Estimate (May 2023)[41]					
TOTAL TONS DELIVERED	[redacted]				
COST PER TON ($/TON)	[redacted]				
OPS WORKPAPER 2DL'S[42]					
TOTAL TONS DELIVERED	[redacted]				
COST PER TON ($/TON)	[redacted]				
FUEL PLAN (SCENARIOS 5 & 6)[43]					
TOTAL TONS DELIVERED	[redacted]				
COST PER TON ($/TON)	[redacted]				

[39] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "01 OpsCostSchedules" 2023 1.5M Opt 2 (1DL) Budget Plan (Sept Fct).
[40] SC/107, Highly Confidential LTFSP at App. 11.
[41] PacifiCorp Confidential Response to Sierra Club Data Request 1.22. Confidential data responses from this proceeding referenced herein are compiled and attached as Exhibit SC/104.
[42] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "01 OpsCostSchedules," 2023 1.5M Opt 1 (2DL's) Budget Plan (Sept Fct).
[43] SC/107, Highly Confidential LTFSP at App. 12.

B. Inclusion of 2023 Costs in PVRR Calculation

Q. You noted that 2023 costs were included in the PVRR calculation. Were you able to quantify what impact the inclusion of the artificially inflated 2023 prices may have had on the final NPVRR of the six Scenarios?

A. Yes, as stated above, inclusion of the 2023 BCC prices, which vary across the scenarios, benefits the Preferred Scenario by between $[redacted] and $[redacted] million when compared to the PVRR of the other scenarios. While this alone would not result in a re-ranking of the six scenarios, in combination with other concerns raised regarding the LTFSP analysis, it suggests that PacifiCorp's cost analysis is not robust. The 2023 costs are both [redacted] for Scenarios 1, 2, and 3, and irrelevant for the purposes of determining the 2024 optimal fueling scenario.

C. PLEXOS Modeling Assumptions

Q. Can you provide additional details on your concerns regarding the comparison of fueling options in the LTFSP analysis?

A. Yes, first we would like to state that the use of PLEXOS for this modeling is an improvement over the Company's past practice of relying on the GRID model. This creates more consistency between the Company's fuel planning and resource planning analyses.

However, the LTFSP analysis could have been more transparent in explaining whether any modeling assumptions unrelated to Jim Bridger coal fuel were based on the 2021 IRP, 2023 IRP, or some other set of inputs. In particular, we are concerned that a large portion of the stated benefits in the Preferred Scenario come from PacifiCorp's assumed ability to sell additional energy to neighboring systems. For example, [redacted] In fact, the lower level of net sales comprises [redacted]% of the difference in revenue requirement (undiscounted) between these alternatives and the Preferred Scenario. Although this may reflect a real cost difference, we consider it risky to plan for higher coal generation from Jim Bridger with the expectation that this generation will readily be purchased from neighboring systems. This is especially true in light of the fact that some states in the region (e.g., Washington and Oregon) have established policies to restrict the inclusion of coal in retail sales over the next few years. Furthermore, the price at which this power would be sold is highly speculative, and so are the estimated revenues.

Highly Confidential Figure 1: Revenue Requirement from Sales and Purchases

[redacted]

Q. Could coal generation from the Jim Bridger plant be replaced by a different resource rather than reducing net sales?

A. Yes. Reducing coal generation from Jim Bridger does not necessarily require a reduction in PacifiCorp's overall *system* generation. Instead, renewable resources could replace that energy, and could probably do so cost-effectively. However, PacifiCorp assumed roughly the same supply from wind, hydro, and other resources (collectively referred to in the LTFSP as "other generation") across each of the six scenarios throughout the LTFSP's timeframe (2023 through 2029).[44] Although it might be appropriate for year 2024 to assume a similar level of new resources across all scenarios, this is not appropriate for later years. Instead, PacifiCorp should have tested the economics of bringing online varying levels of other generation in its LTFSP scenarios. Failing to do so results in an

[44] Refer to SC/107, Highly Confidential LTFSP at Apps. 1-6, row "Other Generation MWh" which [redacted]

underestimation of savings from reducing Jim Bridger coal generation in the system and replacing it with lower cost new resources.

Q. Are resource additions assumed in later years (i.e., after 2024) outside of the scope of this proceeding?

A. Not in the case of Jim Bridger. This is because the PVRR analysis developed through the Jim Bridger LTFSP is not only influenced by longer term resource inputs, but also provides results that can and should be used to inform 2024 fuel-related decisions (e.g., 2024 CSA execution, 2024 affiliate mine planning). Thus, varying the levels of new resource acquisitions in later years of the LTFSP could affect fuel-related decisions made in 2024 and should therefore be examined.

Q. You stated that the Long-Term Fuel Supply Plan analysis shows "other generation" (e.g., wind, hydro, etc.) to be approximately the same across different scenarios. Is this true for all years?

A. No. In 2024 there is actually a substantial difference in "other generation" between Scenario 4 and the Preferred Scenario. Below is a table that summarizes these two scenarios for 2024.

Highly Confidential Table 7: Resource Generation Under Scenario 4 and the Preferred Scenario

	MWh			*$000*		
	Scenario 4	Preferred Scenario	Delta	Scenario 4	Preferred Scenario	Delta
JB Fuel - Coal[45]	[redacted]					
Fuel - Coal (incl. JB)[46]						
Fuel - Gas						
Purchased Power						
Wholesale Sales						
Other Generation (Hydro, Wind, etc.)						
Total System						

[45] *Id.* at Apps. 11, 12, and 13

[46] *Id.* at Apps. 4, 5, and 6. Source for all following table rows.

Notably, the results show over [redacted] "other generation" in the Preferred case. It is not clear to us what could cause such a [redacted] in "other generation" over Scenario 4, especially when coal output is also [redacted] Meanwhile, the Preferred Scenario also shows a [redacted] amount of purchased power ([redacted] less) and a [redacted] amount of wholesale sales ([redacted] more). When taken together the total amount of wholesale sales (net of purchased power) was about [redacted] greater in the Preferred Scenario. This is significant because, as mentioned previously, nearly all of the economic benefit of the Preferred Scenario (versus Scenario 4) can be explained by the increase in wholesale sales. Yet, in turn, nearly all of the difference in wholesale sales between the scenarios appears to be attributable to differing amounts of "other generation" in 2024 rather than differing outputs from the Jim Bridger plant.

Q. What are your concerns based on this assessment and what steps should the Commission take to address them?

A. We are concerned that PacifiCorp may have included inconsistent (and potentially inappropriate) input assumptions for "other generation" when analyzing different scenarios in the LTFSP. These inconsistencies in "other generation" may be the primary reason the Preferred Scenario appears economically favorable, even though they are irrelevant to the Jim Bridger coal fuel supply selected. Given these concerns, the Commission should apply caution when considering the overall coal volume (and associated coal fuel costs) it approves for Jim Bridger in the 2024 TAM. We believe a volume consistent with Scenario 4 may be more appropriate at this time.

D. <u>Limited assessment of scenarios with an earlier closure date for Bridger Coal mine</u>

Q. In the 2023 TAM, Sierra Club witness Ed Burgess had recommended that future iterations of the plan should be required to evaluate a scenario where no new coal is sourced after 2025 and Jim Bridger relies on stockpiled coal. Was this scenario included?

A. PacifiCorp modeled Scenario 3 which assumes "[redacted]."[47] However, they did not model a scenario that would operate the Bridger mine until 2025, terminate the Black Butte supply at the end of 2023, and rely on stockpiled coal after 2025 for the remaining years of coal operations at the Jim Bridger units. This scenario could eliminate the risk of only relying on third party supply, but also reduce costs and risks associated with maintaining mine operations as fossil fuel generation becomes increasingly more expensive. It is worth noting that since the 2023 TAM in which witness Mr. Burgess argued that stockpiled coal could supply Jim Bridger operations after 2025, the Company has further accelerated the termination of coal operations at the Jim Bridger plant in its 2023 IRP (from 2037 to 2030). Such a fueling scenario would mean that PacifiCorp should begin to minimize new capital investments and other incremental fixed costs at the mine immediately, resulting in savings for ratepayers while also providing time for the Commission to evaluate how to treat certain fixed mining costs such as depreciation and whether recovery of those costs should be accelerated and/or eligible for recovery through other mechanisms outside of the TAM.

E. ***Recommendations***

Q. You previously mentioned that you recommend PacifiCorp align the Bridger coal supply in the 2024 TAM with Scenario 4 of the LTFSP. Can you provide additional details on that?

A. Yes. Our review of the LTFSP has revealed several methodological concerns and inconsistencies. Out of the stated $[redacted] difference in the net present value of revenue requirement between Scenario 4 and the Preferred Scenario or $[redacted] of

[47] *Id.* at 6.

undiscounted revenue requirement,[48] $[redacted] is based on an irrelevant and incorrect cost difference in 2023 costs,[49] $[redacted] is based on a [redacted] due to an unjustified [redacted] in other generation ([redacted]),[50] and $[redacted] is due to differences post-2025 that depend on inconsistent pricing assumptions and speculative assumptions about the price of purchases/sales out of the system. Post-2025 savings are also inflated as they overestimate the cost of replacing generation from Jim Bridger by not allowing new resources, as already explained in Section 5(A). Thus, out of the $[redacted], less than $[redacted] can be attributed to the differences in the fueling plan between Scenario 4 and the Preferred in 2024. Additionally, Scenario 4 would be subject to lower capital costs as shown in Table 2 of the LFTSP. Although not recovered in TAM, those should still be included in the analysis (similar to PacifiCorp's inclusion of capital costs for Scenario 2). Finally, even for 2024, the $/ton price for supply at the Bridger plant is inconsistent with what PacifiCorp is requesting to recover in the TAM, making the 2024 savings speculative. Based on this, and the reduced risk of Scenario 4, we believe that Scenario 4 is a better fueling option than the Preferred Scenario.

Q. What recommendations do you have for the Commission regarding the LTFSP?

A. Our recommendations are as follows:

1. The Commission should not rely on the PacifiCorp Preferred Scenario for the determination of prudent Jim Bridger fuel supply levels. The benefits of that scenario versus others has been inflated by several factors, including: a) relying on 2023 Bridger Coal costs that are both incorrect and irrelevant, b) [redacted] "other generation" for different scenarios in 2024, c) projecting portfolio costs in the future without allowing coal to be economically replaced by other resources, thus undermining the robustness of the Long-Term Fuel Plan (including for 2024 fuel decisions).

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[48] *Id.* at Table 2; *id.* at Apps. 4, 5.
[49] *Id.* at Apps. 4, 5.
[50] SC/100, Highly Confidential Table 6: Revenue Requirement from Sales and Purchases.

2. The Commission should require an updated Long-Term Fuel Plan for Jim Bridger in every subsequent TAM proceeding. While the Commission's Order in the 2023 TAM adopted a settlement agreement including an agreement that PacifiCorp would update the Long-Term Fuel Plan every two years, aligned with its IRP, the rapidly changing economics at Jim Bridger make yearly updates to the Plan more prudent.

3. Future iterations of the Plan should use PLEXOS or AURORA, while clearly identifying the assumptions that are included. Aggregate coal, gas, sales, purchases, and other generation should be reported in a way that can be directly compared with the NPC components. The plan should be produced with all its accompanying workpapers.

4. Future iterations of the Plan should allow for Jim Bridger generation to be replaced not only by other coal or gas generation, or system purchases, but also new resources.

5. Future iterations should continue to include a scenario without minimum take assumptions from the Bridger mine for either the base or supplemental volumes or any other coal supply without a Commission approved CSA. The scenario should also allow for economic cycling of all coal units and not include a minimum fuel burn constraint. It should use average prices and determine volumes based on the optimization.

6. Finally, future iterations should be required to evaluate a scenario where no new coal is sourced from the Bridger mine after 2025 and Jim Bridger relies on stockpiled coal.

6. <u>Hunter Plant Coal Supply Agreements</u>

Q. Please summarize the changes in coal supply volumes and costs to supply the Hunter plant since the 2023 TAM proceeding.

A. The Hunter plant received less than forecasted (and contracted for) coal in late 2022 and 2023, resulting in a reduction of its stockpile.[51] PacifiCorp has amended, contracted, and is negotiating CSAs for the supply of the plant. PacifiCorp anticipates there will be a continuation of coal supply shortages and market instability in 2024.[52] In comparison to the 2023 TAM, the estimated amount of coal burned to supply the Hunter plant for the 2024 TAM decreased by [redacted]% while the prices increased by [redacted]%.[53]

Q. Has PacifiCorp included volumes and prices from any new CSAs, new CSA amendments or future CSAs to supply the Hunter plant for the 2024 TAM?

A. Yes. PacifiCorp included the new CSA with Gentry Mountain Mining, LLC (Gentry CSA) for years 2023-2025 and the amended contract with Bronco Utah Operations, LLC (Second Amendment and Third Amendment to the Bronco CSA). The Company also included future coal volumes and pricing from a speculative new contract with [redacted] that has not yet been executed. For the 2024 TAM, the total volume of the [redacted] and Gentry CSAs [redacted]. However, for the Bronco CSA, PacifiCorp assumes [redacted] tons consumed in the 2024 TAM forecast while the residual contracted tons will be used to balance the inventory.

Highly Confidential Table 8: New, Amended, and Future CSAs for Hunter Plant (all owners)

PacifiCorp Assumed Contract	2024 Delivered Tons	Consumed Coal in 2024 TAM [redacted]	2024 Price/Ton (delivered)
New Executed Gentry CSA[54]	[redacted]	[redacted]	[redacted]

[51] PAC/200 at Owen/6:5-7. *See also* Highly Confidential Ex. Accompanying Direct Test. of James Owen Hunter/Gentry CSA Analysis at Owen/1 [hereinafter "PAC/201"].
[52] PAC/200 at Owen/6:8-9
[53] Confidential Workpaper Accompanying Direct Test. of James Owen (PAC/200), "CONF Cost Comparison 2024 TAM Directv4.xlsx."
[54] PAC/200 at Owen/15:15 and Owen/15. The price per ton differs from what can be found in Owen/23:5, as well as in the Company's workpapers and in the NPC calculation. In their response to Sierra Club Data Request 1.13, the Company states that the values in the workpapers are "out of date." (Ex. SC/104)

Third Amendment to Bronco CSA[55]	[redacted]
Speculative Future [redacted] CSA[56]	[redacted]

Q. How were fuel costs associated with these contracts modeled in AURORA for the 2024 TAM?

A. PacifiCorp assumes that all the consumed coal [redacted][57] [redacted] a monthly fixed cost that did not impact the optimization modeling in AURORA.[58] Furthermore, according to PacifiCorp's workpapers,[59] to [redacted]

[redacted]

Q. Have you reviewed the analysis the Company provided in its evaluation of the new, amended, and future CSAs to supply the Hunter plant?

A. Yes. The Company's analysis was provided in Highly Confidential Exhibit PAC/201 for the new Gentry CSA, Highly Confidential Exhibit PAC/204 for the amended Bronco CSA, as well as highly confidential workpapers accompanying the Direct Testimony of

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[55] PAC/200 at Owen/17:10, 14.
[56] SC/104, PacifiCorp Confidential Response to OPUC Data Request 36(a); PAC/200 at Owen/17:16.
[57] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24_Mitchell Direct Mar 2023 CONF" at 'Coal Expense Calculation' tab.
[58] SC/103, PacifiCorp Response to Sierra Club Data Request 2.3(d).
[59] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "Aurora GN Fuel Prices CONF."

James Owen.[60] For the future CSA with [redacted], PacifiCorp stated that "[s]upporting analysis will be provided once the contract has been completed."[61] However, PacifiCorp's testimony stated that "the price of delivered coal from [redacted] increased from [redacted] in the 2023 TAM to [redacted] in the 2024 TAM" and that the increase "reflects the pricing received as a result of the RFP process."[62] In its Confidential Response to OPUC Data Request 36, PacifiCorp additionally stated that [redacted][63] A bid reflecting the volume and price of the future [redacted] contract is included in the Company's highly confidential workpapers for the valuation of the Gentry and Bronco CSAs.

Q. Please summarize the RFP analysis for the Gentry CSA.

A. The RFP analysis evaluated [redacted][64] [redacted][65] These scenarios were assessed through analysis runs using the PLEXOS model, to determine the value of the potential combinations of contracts.

Q. What were the findings of the Gentry CSA analysis?

A. The analysis found that the [redacted]

[60] Highly Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "PacifiCorp HIGHLY CONFIDENTIAL Hunter Analysis by Bid Number Workpapers (5-8-23)"; Highly Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "Hunter RFP Analysis by Bid Number_2022 11 29 HCONF FINAL."
[61] PacifiCorp Highly Confidential Response to Sierra Club Highly Confidential Data Request 1.12(b). Highly Confidential data responses from this proceeding referenced herein are compiled and attached as Exhibit SC/105.
[62] PAC/200 at Owen/17:14-16.
[63] SC/104, PacifiCorp Confidential Response to OPUC Confidential Data Request 36(b).
[64] SC/105, PacifiCorp Highly Confidential Responses to OPUC Data Request 39.
[65] PAC/201 at Owen/8.

[redacted]

Q. Do you have any concerns about the Gentry CSA analysis?

A. Yes. We have several concerns with the CSA analysis. First, the analysis provided was not properly documented. The exhibits state that PLEXOS was used to simulate different fueling scenarios reflecting the RFP bids, but the workpapers provided do not include the full set of PLEXOS inputs and outputs, making it difficult to fully understand the conditions under which each bid was evaluated and the system impacts. Second, the [redacted] for Hunter both in the Gentry analysis, as well as the Bronco analysis, [redacted] in the TAM analysis or the average cost run results, raising concerns about assumptions that might have led to [redacted] in the CSA assessments. Third, the modeled cost for the Gentry supply reflects a value that is inconsistent with what is found in the Company's workpapers and Confidential Table 3, in PAC/200.[66] Fourth, the results for the Gentry CSA under some of the PacifiCorp assessed sensitivities indicate that the CSA does not necessarily result in benefits for ratepayers. Finally, PacifiCorp's workpapers indicate that several bids were available for selection at the time of the Gentry CSA. It is not clear to us why PacifiCorp chose the Gentry CSA for assessment, instead of doing a comprehensive evaluation of the responses that might have led to a different selection of bids.

Q. Can you provide additional details on your concerns for the CSA methodology?

A. Yes. First, the analysis does not comprehensively review all bids. Even if PacifiCorp had to order the RFP responses to evaluate them it is not clear [redacted] We understand that [redacted]

[66] PAC/200 at Owen/15:15 and Owen/15. The price per ton differs from what can be found in PAC/200 at Owen/23:5, as well as in the Company's workpapers and in the NPC calculation. In their response to Sierra Club Data Request 1.13, the Company states that the values in the workpapers are "out of date." (Ex. SC/104)

[redacted]

Q. What other coal volumes from third party sellers were available to supply Hunter at the time PacifiCorp evaluated the Gentry CSA?

A. According to PacifiCorp's workpaper accompanying the Hunter RFP analysis,[67] [redacted] For the evaluation of the Gentry CSA, PacifiCorp modeled [redacted].[68] As shown in PacifiCorp's workpapers,[69] the Company assumed a volume of [redacted].[70] Collectively, the volumes available from [redacted]. Assuming an 85% ownership share for the Hunter plant, [redacted] could provide approximately [redacted] for PacifiCorp.

Q. Would these volumes be sufficient to meet PacifiCorp's coal demand to fuel Hunter in 2024?

A. Yes, according to the model runs performed by the Company for the 2024 TAM. In its workpapers, PacifiCorp reports [redacted] MMBtus of fuel burned to power the Hunter plant in the runs conducted for the NPC analysis.[71] Furthermore, the modeling runs performed using the average coal price resulted in the consumption of [redacted]

[67] Highly Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "Hunter RFP Analysis by Bid Number_2022 11 29 HCONF FINAL."
[68] PAC/201 at Owen/7.
[69] Highly Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "Hunter RFP Analysis by Bid Number_2022 11 29 HCONF FINAL."
[70] PAC/201 at Owen/7.
[71] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24_Mitchell Direct Mar 2023 CONF."

MMBtus at Hunter, assuming a cost of [redacted],[72] [redacted].[73] Considering both that the [redacted],[74] [redacted],[75] it is not clear why the Gentry CSA was necessary at all. This suggests that PacifiCorp may have overstated the demand for coal at Hunter when evaluating the Gentry CSA. At minimum, PacifiCorp has not sufficiently demonstrated the need for a new contract with Gentry or the minimum take requirement associated with this agreement.

Q. PacifiCorp witness James Owen states that "[t]he model selected all proposed coal supplies available at the Hunter plant and would have selected additional coal volumes if they were available in 2024 and 2025,"[76] but you suggest that even the Gentry supply might not have been necessary. Can you explain?

A. Yes. The model runs in the CSA analysis result in [redacted] than either the 2024 TAM or the average cost run. We do not have full visibility into what caused the differences between these model runs but are concerned about the inconsistency, given that [redacted] was relied upon for the execution of the Gentry CSA. Specifically, the Hunter CSA analysis [redacted] for Hunter at [redacted] while the average cost run results in lower demand, even when a lower price is assumed,[78] at [redacted]. The Bronco analysis further increases the 2024 demand to [redacted].

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[72] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24 Average Fuel Cost NPC CONF."
[73] PAC/201 at Owen/7.
[74] SC/104, PacifiCorp Confidential Response to OPUC Data Request 28.
[75] PAC/200 at Owen/17:10.
[76] PAC/200 at Owen/11:6-8.
[77] Highly Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "Hunter RFP Analysis by Bid Number_2022 11 29 HCONF FINAL" at tab PivotHTR
[78] Highly Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "PacifiCorp HIGHLY CONFIDENTIAL Hunter Analysis by Bid Number Workpapers (5-8-23).xlsb"

Q. You also mention an inconsistency to the Gentry price. Can you provide additional details?

A. Yes. The price of the Gentry CSA is reported as $[redacted]/ton in the table on page 15 of Mr. Owen's Direct Testimony. However, in Table 3, the price is reported as $[redacted], which is also the price found in the majority of the Company's workpapers and what was used to estimate the NPC in the 2024 TAM.[79] The CSA analysis uses the [redacted] price estimate. In their response to Sierra Club Data Request 1.13, the Company states that the values in the workpapers are "out of date." This creates some uncertainty around the value of the Gentry CSA, while it might have also introduced errors in the amount PacifiCorp is requesting for cost recovery.

Q. Finally, you express concerns about the decision to execute the Gentry CSA based on PacifiCorp's results. Can you provide additional details?

A. Yes. PacifiCorp seems to have assessed the benefit of additional supply for Hunter by conducting runs with different supply prices and then comparing the cost of the available supply and the incremental system benefit. According to their results, the Gentry supply [redacted][80] [redacted][81] Thus even if in the expected case PacifiCorp calculates net benefits, [redacted]. This result combined with the [redacted], the [redacted], and the fact that other RFP responses were not evaluated raises concerns for the analysis, the robustness of the recommendation, and the prudency of the Gentry CSA. Had PacifiCorp assessed other bids, it is possible that they could have found a more economic option to supply the plant. For example, [redacted]

[79] PAC/200 at Owen/23:5.
[80] PAC/201 at Owen/6.
[81] *Id*.

Q. Do you have any concerns related to the [redacted]?

A. Yes. As noted previously [redacted] It is especially troubling for contracts and amendments that result in a [redacted] price increase from the 2023 TAM, while at the same time the contract might not even protect ratepayers from fuel shortages and price increases. Furthermore, there is no existing contract for [redacted] to supply coal to the Hunter plant in 2024 and [redacted], nor has it shown that both these costs and the Company's estimated future fuel consumption from [redacted] could not be reduced or eliminated in advance of the 2024 operating year.

Q. What action do you recommend the Commission take regarding PacifiCorp's proposed costs for the Hunter coal supplies?

A. Although the future [redacted] CSA has not been executed or reviewed by the Commission, [redacted] we are not making a disallowance recommendation at this time. However, we find that executing the Gentry CSA when other options were available at lower prices was imprudent and the associated costs ($[redacted] Oregon allocated)) should be disallowed (furthermore the 2024 TAM and amount for recovery includes an "out of date" assumption for the Gentry price, meaning that PacifiCorp through its application is actually requesting cost recovery of [redacted] Oregon allocated)).

7. <u>Participation in the Extended-Day Ahead Market</u>

Q. What is the Extended-Day Ahead Market ("EDAM")?

A. EDAM is a voluntary day-ahead electricity market that is intended to facilitate increased regional coordination throughout the West. It is an extension of the current Western Energy Imbalance Market ("EIM"), which is currently limited to real-time transactions.

Q. Do you know whether PacifiCorp is planning to join EDAM?

A. Yes. PacifiCorp announced its plans to join EDAM in December 2022.[82] According to the Company's announcement, EDAM will begin operation in 2024, subject to federal regulatory approval. This timeframe overlaps with the 2024 NPC projections PacifiCorp has provided as part of its application in this proceeding. Thus, PacifiCorp's participation in EDAM in late 2024 will likely have a significant effect on the operation of its generation fleet and in turn a portion of its 2024 NPC calculations. This will be even more true in future TAM cycles.

Q. Do you have any concerns about PacifiCorp joining EDAM?

A. Yes, on a few limited issues. While we generally support PacifiCorp's stated intention of joining the EDAM, there are some potential consequences that should be considered by the Commission well in advance to ensure PacifiCorp's participation maximizes ratepayer benefits. Namely, since PacifiCorp recovers its fuel costs through TAM proceedings, like this one, the Company will not be reliant on revenue from the EDAM market to fully recover its operating costs. This may impact the way that the Company approaches dispatch decisions, as witness Ed Burgess has discussed in past TAM proceedings.[83]

When an energy seller is reliant on a competitive market to recover operating costs, it is optimal for the seller to bid their resources into the market at the marginal cost of generation. However, when the seller can recover some, or all, of their operating costs outside of the market (e.g., through the TAM), they are incentivized to understate their marginal costs in order to clear the market and gain additional market revenue. By understating costs,

[82] *PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market* (Dec. 8, 2022), *available at* https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html#:~:text=Plans%20call%20for%20the%20EDAM,grid%20operators%2C%20PacifiCorp%20and%20CAISO.

[83] *See In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Ore. Pub. Util. Comm'n Dkt. No. UE-375, Direct Test. of Ed Burgess on Behalf of Sierra Club (SC/100) at 65:14-66:16, *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue375htb174343.pdf.

sellers may artificially lower the market clearing price, under-compensating other resources that clear and ultimately resulting in distorted market signals. This can also result in increased costs to customers, both in the short term and in the long term as efficient investment is disincentivized.

Q. Do these concerns have any specific relevance to PacifiCorp's coal fleet?

A. Yes. This is of particular concern with respect to PacifiCorp's coal fleet since one of the potential rationales for reducing a generation unit's market bid below its marginal cost[84] is a minimum-take provision such as those included in many of PacifiCorp's CSAs. As discussed in Section 8 of our testimony, PacifiCorp has historically modeled take-or-pay provisions as fixed costs in their dispatch modeling, thereby excluding those cost from the unit's short-run marginal costs. This has the effect of reducing the modeled dispatch cost of the generation unit. This is true in both annual TAM projections as well as near-term operating decisions. Such a practice can lead to distorted market pricing and generation dispatch decisions over time. While there are limited cases in which this practice may be justified in the short-run, it results in a suboptimal operational strategy over the long run. In the context of a regional market, it is possible that PacifiCorp might extend this practice of using distorted (i.e., reduced) costs in its market bid prices. The resulting suboptimal dispatch decisions are likely to extend to customers across the system, with PacifiCorp's ratepayers being the ones bearing most of the impact.

Q. How might take-or-pay minimums from CSAs be reflected in the bid prices of PacifiCorp's coal generation units that participate in the EDAM?

A. Absent strong Commission oversight, we believe PacifiCorp is likely to offer these units into the market either a) at a bid price that is unreasonably low relative to its long-run marginal costs, or b) as a "self-scheduled" or "must run" unit that is not dispatched by the market operator. In either case, the end result will be overgeneration of PacifiCorp's coal fleet (relative to what is economic over the long-run), and distortions to the market that will crowd out cleaner, more efficient generation.

[84] In this case, we are primarily focused on the medium- to long-run marginal cost (i.e., over several months or years), which is relevant to portfolio investment decisions and overall customer bills versus the short-run marginal cost which may be more relevant to daily system operations.

Q. Do you have any recommendations regarding PacifiCorp's participation in EDAM?

A. Yes. To start, we believe that additional reporting requirements can support the existing regulatory oversight mechanisms, such as the Commission's oversight of cost recovery in future TAM cycles. For example, the Commission could require PacifiCorp to provide frequent reporting (e.g. quarterly) comparing the marginal costs of its generation units to their market offer prices on an hourly basis. More specifically, we recommend the following increased reporting requirements: the utility should provide additional hourly data at the unit level for each thermal unit, such as market bid details, whether the bid cleared, market revenue received, recoverable fuel cost, generation level. They should also share information from the system level, specifically the marginal price and marginal unit. This would allow regulators and intervenors to ensure that thermal units are being dispatched in a manner that minimizes cost to customers.

Q. Are there additional requirements that should be considered over time?

A. Yes. Over time, one way to avoid the market distortions described above would be to require PacifiCorp to bid in the full cost of its coal units to EDAM, including the full costs (i.e., "average costs") of any coal that may be subject to a take-or-pay provision. Such a requirement could be phased in at a future date certain to ensure sufficient time to address existing CSA provisions. However, once established, such a requirement would enhance competition by ensuring PacifiCorp is on an equal footing with independent power producers, which by necessity must recover their full operating costs (including fuel) through market revenues. As an equivalent alternative to requiring bids to match costs, the Commission could also place some limitation on future fuel cost recovery via the TAM that is linked to EDAM market awards.

Q. What immediate recommendations do you have for the Commission regarding oversight of PacifiCorp's participation in the EDAM?

A. We recommend that the Commission host one or more stakeholder workshops to discuss best practices for utility participation in wholesale markets. These workshops should address the potential risks of market distortion through generator bid price offers and/or self-scheduling, as well as solutions for addressing these risks, including oversight through future TAM proceedings.

8. Average Cost Run in the 2024 TAM

Q. For the 2024 TAM filing, did PacifiCorp perform any modeling runs that remove minimum take provisions and use an average coal price for dispatching coal plants?

A. Yes. As required in Order No. 20-392, PacifiCorp performed an informational model run that removed operational constraints related to assumed minimum take requirements in the CSAs and instead used an average coal price for purposes of dispatching coal plants.[85]

Q. Have you reviewed the information PacifiCorp provided supporting this average cost modeling run?

A. Yes. Support for this analysis was provided in PacifiCorp's workpapers.[86] As shown in these workpapers, the coal plants are dispatched without a take-or-pay requirement, and use an average price reported in $/MMBtu.

Q. How did the reported dispatch and costs differ in the average cost run, compared to the run presented for the NPC analysis used in the 2024 TAM filing?

A. In the modeling run using the average coal price, the overall generation from these plants for 2024 was [redacted]% lower than in the runs used in PacifiCorp's TAM analysis. Total costs reported PacifiCorp's workpapers were also [redacted]% lower in the average cost run, accounting for a difference of $[redacted] million.

Confidential Table 9: TAM and Average Cost Run Comparison

Plant	*Take-or-Pay Consumption (MMBtu)*[87]	*Tier 1 Price ($/MMBtu)*[88]	*Total Consumption (MMBtu)*[89]	*Total Generation (MWh)*[90]	*Generation Variance*

[85] PAC/100 at Mitchell/27:17-19.
[86] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24 Average Fuel Cost NPC CONF."
[87] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF" at Coal Expense Calculation tab.
[88] *Id.*
[89] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24 Average Fuel Cost NPC CONF" and OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF" at NPC Summary tabs.
[90] *Id.*

Colstrip	[redacted]
TAM RUN	
Avg Cost	
Run	
Craig	
TAM RUN	
Avg Cost	
Run	
Dave Johnston	
TAM RUN	
Avg Cost	
Run	
Hayden	
TAM RUN	
Avg Cost	
Run	
Hunter	
TAM RUN	
Avg Cost	
Run	
Huntington	
TAM RUN	
Avg Cost	
Run	
Jim Bridger	
TAM RUN	
Avg Cost	
Run	
Naughton	

TAM RUN	[redacted]
Avg Cost Run	
Wyodak	
TAM RUN	
Avg Cost Run	

Q. Are there any specific differences that are particularly concerning?

A. Yes. The difference in results for both the Hunter and Dave Johnston plants are seemingly counterintuitive. For example, according to PacifiCorp's workpapers, the Company assumed a marginal cost of [redacted] for Hunter in 2024 for the modeling run used in the TAM analysis,[91] and a cost of [redacted]/MMBtu in the modeling run using the average cost of Hunter coal.[92] Despite this cost difference, the dispatched MWh for the Hunter plant was only [redacted]% lower in the average cost run. Conversely, the output MWh for the Dave Johnston plant was [redacted]% lower in the average cost run even though this run assumed an average coal price of just [redacted] Although the removal of the minimum take requirements that are assumed for [redacted] of Dave Johnston's coal contracts would be expected to decrease generation at the plant, it is surprising that the model selected Dave Johnston significantly less often, given its relatively low average cost. One would expect that one of the lowest cost coal plants in PacifiCorp's fleet would not be impacted substantially when being dispatched at its average coal price.

Q. Do you have any concerns about the total 2024 costs reported for the model run using average coal prices?

A. Yes. In the workpapers that PacifiCorp provided to support the average cost run,[93] the calculation of the total costs for the coal fleet appears to be overestimated. In the

[91] Confidential Workpapers Accompanying PacifiCorp's 2024 TAM Appl., "Aurora GN Fuel Prices CONF" and "_OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF."
[92] Confidential Workpaper Accompanying PacifiCorp's 2024 TAM Appl., "ORTAM24 Average Fuel Cost NPC CONF."
[93] *Id.*

provided spreadsheet, PacifiCorp shows a total cost of approximately [redacted] for these plants in 2024. However, these costs are calculated using a methodology that takes the maximum of each plant's operating cost, calculated as MMBtu consumption multiplied by the average $/MMBtu cost, and the plant's annual fixed costs for 2024, which are based on the cost of volumes subject to minimum take requirements. This results in including costs for take-or-pay volumes that may not be selected in the average cost run and that might not exist at this time (for future CSAs or even the Bridger coal costs), ultimately overstating the total costs from this informative analysis. We estimate that if PacifiCorp had instead calculated costs for these plants based only on the volume of coal consumed for generating the dispatched MWh, the total cost for the coal fleet would be approximately [redacted] lower ([redacted]%) than the total cost from the model run used in the TAM analysis.

Q. Do you have a recommendation for the average cost run in future TAM proceedings?

A. Yes. We believe that this informational run can provide the Commission and intervenors with valuable information as they review the Company's TAM, and should continue to be included. We recommend that this run should remove any modeling constraints that would result in coal generation that is not economic: the tiered approach with the first tier minimum take being available at $0/MMBtu, the minimum fuel burn constraints, the inclusion of fixed costs for minimum take requirements even if those were not selected, the must run designation for coal units, as well as any other constraint that might result in uneconomic operations of the coal units. The average cost run was proposed when PacifiCorp was using the GRID modeling tool, which could not explicitly model different cost tiers. Now that PacifiCorp uses AURORA, this informational run could evolve to what it was really meant to capture: the economics of coal generation under the assumption of no minimum take provisions. This means that PacifiCorp can model the different contracts or tiers in a contract with their full price per contract/tier, instead of an average cost. This would provide visibility into the incremental benefit/cost of each contract and the optimal fuel burn. Given the need to focus on new, amended, or future contracts, we are also recommending that the Commission require PacifiCorp to conduct another run in which only the new, amended, or future contracts would be modeled with their full cost per contract/tier. This would avoid inconsistencies between the TAM assumptions and the CSA evaluations as those seen in the Hunter analysis this year. The run should also eliminate any minimum fuel burn or must run constraints

Q. Does this conclude your testimony?

A. Yes, it does.

Docket No. UE 420

Exhibit SC/101

Witnesses: Ed Burgess and Maria Roumpani

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/101
Curriculum Vitae of Ed Burgess

Edward Burgess

Senior Director

Ed leads the integrated resource planning practice at Strategen. Ed has served clients including consumer advocates, public interest organizations, Fortune 500 companies, energy project developers, trade associations, utilities, government agencies, universities, and foundations. He has led or contributed to expert testimony, formal comments, technical analyses, and strategic grid planning efforts for clients in over 25 states. These have focused on a range of topics including resource planning and procurement, utility system operations, transmission planning, energy storage, electric vehicles, utility rates and rate design, demand-side management, and distributed energy resources.

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Education

PSM
Solar Energy Engineering and Commercialization
Arizona State University
2012

MS
Sustainability
Arizona State University
2011

BA
Chemistry
Princeton
2007

STRATEGEN.COM

Work **Experience**

Senior Director

Strategen / Berkeley, CA / 2015 - Present

+ Focuses on energy system planning via economic analysis, technical regulatory support, integrated resource planning and procurement, utility rates, and policy & program design.
+ Supports clients such as trade associations, project developers, public interest nonprofits, government agencies, consumer advocates, utilities commissions and more.

Senior Policy Director

Vehicle-Grid Integration Council / Berkeley, CA / 2019 - Present

+ Leads advocacy and regulatory policy for a group representing major auto OEMs and EVSEs
+ Advances state level policies and programs to ensure the value from EV deployments and flexible EV charging and discharging is recognized and compensated
+ Leads all policy development, education, outreach, and research efforts

Consultant

Kris Mayes Law Firm / Phoenix, AZ / 2012 - 2015

+ Consulted on policy and regulatory issues related to the electricity sector in the Western U.S.

Consultant

Schlegel & Associates / Phoenix, AZ / 2012 - 2015

+ Conducted analysis and helping draft legal testimony in support of energy efficiency for a utility rate case.

Edward Burgess

Senior Director

STRATEGEN

Selected Recent Publications

+ New York BEST, 2020. *Long Island Fossil Peaker Replacement Study.*
+ Ceres, 2020. *Arizona Renewable Energy Standard and Tariff: 2020 Progress Report*.
+ Virginia Department of Mines and Minerals, 2020. "*Commonwealth of Virginia Energy Storage Study*.
+ Sierra Club, 2019. *Arizona Coal Plant Valuation Study.*
+ Strategen, 2018. *Evolving the RPS: Implementing a Clean Peak Standard*."
+ SunSpec Alliance for California Energy Commission.,2018. *Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California*.

Domain Expertise

Vehicle Grid Integration

Distributed Energy Resources

Electric Vehicle Rates, Programs and Policies

Energy Resource Planning

Benefit Cost Analysis

Electricity Expert Testimony

Stakeholder Engagement

Energy Policy & Regulatory Strategy

Energy Product Development & Market Strategy

STRATEGEN.COM

Relevant Project Experience

Arizona Residential Utility Consumer Office (RUCO)

IRP Analysis and Impact Assessment / 2015 - 2018

+ Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
+ Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
+ Ed was the lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 - 2019

+ Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003)
+ Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 - 2017

+ Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years. Ed served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of Consumer Advocate

NEM Successor Tariff Design / 2016

+ Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Relevant Project Experience (con't)

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 - 2020

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
+ Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
+ Worked with Strategen technical team on utilizing a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 - 2019

+ Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage

Portland General Electric

Energy Storage Strategy / 2016

+ Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
+ Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
+ Supported development of a competitive solicitation process for storage technology solution providers.

Xcel Energy

Time-of-use Rates / 2017 - 2018

+ Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Sierra Club

PacifiCorp 2021 IRP Technical Support / 2020 - 2021

+ Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
+ Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General

Duke Energy 2020 IRP Technical Support / 2020 - 2021

+ Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
+ Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota

Energy Storage Stakeholder Workshops / 2016 - 2017

+ Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
+ Conducted study on the use of storage as an alternative to natural gas peaker.
+ Presented workshop and study findings before the Minnesota Public Utilities Commission.

Edward Burgess

Senior Director

STRATEGEN

Expert Testimony

California Public Utilities Commission

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)
- Pacific Power 2022 Energy Cost Adjustment Clause (Docket No. A.21-08-004)
- Pacific Gas and Electric's Day-Ahead Real Time Rate and Pilot (Docket No. A.20-10-011)
- Pacific Gas and Electric's Electric Vehicle Charge 2 Application (Docket No. A.21-10-010)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

Colorado Public Utilities Commission

- Tri-State Generation and Transmission Application for a CPCN (Docket No. 22A-0085E)

Indiana Utility Regulatory Commission

- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause – Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Louisiana Public Service Commission

- Entergy Certification to Deploy Natural Gas Distributed Generation (Docket No. U-36105)

Massachusetts Department of Public Utilities

- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Michigan Public Service Commission

- Consumers Energy 2021 Integrated Resource Plan (Docket No. U-21090)

Nevada Public Utilities Commission

- NV Energy's Integrated Resource Plan in (Docket No. 20-07023)

North Carolina Utilities Commission

- Duke Energy Carbon Plan (Docket No. E-100, Sub 179)

Oregon Public Utilities Commission

- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)
- Northwest Natural 2022 General Rate Case (Docket No. UG-435)

Expert Testimony (con't)

South Carolina Public Service Commission

- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Washington Utilities and Transportation Commission

- Avista Utilities 2020 General Rate Case (Docket No. UE-200900)
- Avista Utilities 2022 General Rate Case (Docket No. UE-220053/UG-220054)
- Puget Sound Energy 2022 General Rate Case (Docket No. UE-220066/UG-220067)

Docket No. UE 420

Exhibit SC/102

Witnesses: Ed Burgess and Maria Roumpani

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/102
Curriculum Vitae of Maria Roumpani

Maria Roumpani, PhD

Technical Director

Maria is the Technical Director of the Strategen Consulting practice. Maria leads the economic and technical grid modeling and analysis for the firm, including capacity planning, production cost, and energy storage dispatch modeling.

Maria has served clients including consumer advocates, public interest organizations, energy project developers, trade associations, government agencies, and foundations.

Contact

Location
Berkeley, California

Email
mroumpani@strategen.com

Phone
+1 (510) 462-9728

Education

PhD
Management Science and Engineering
Stanford University
2018

MSc
Electrical & Computer Engineering
National Technical University of Athens
2009

STRATEGEN.COM

Work Experience

Strategen

Technical Director / Berkeley, CA / 2017 - Present

+ Leads firmwide technical and economic modeling and analysis to support Strategen consulting engagements. Specializes in the use of modeling tools (capacity expansion, production cost models) to inform grid planning and decarbonization issues.

Precourt Institute for Energy, Stanford University

Research Assistant / Palo Alto, CA / 2011-2017

+ Conducted research in a wide range of topics, from game theoretical approaches in electricity markets to behavioral economics. Representative projects:
    + Model for the competition in a two-settlement electricity market, capturing issues of market power and risk aversion
    + Border carbon adjustment in international trade
    + Model for electric vehicle infrastructure
    + Framework for energy efficiency measure classification to inform behavioral program design

Stanford University

Teaching Assistant / Palo Alto, CA / 2012 - 2017

+ Designed teaching material & led teaching sessions evaluated as an extremely effective teaching assistant

Energy, Economics, & Environment Modeling Laboratory, National Technical University of Athens

Researcher / Athens, Greece / 2009-2010, 2015

+ Mathematical modeler developing large scale energy planning models (focusing on capacity expansion of electricity supply)

Maria Roumpani, PhD

Technical Director

STRATEGEN

Domain Expertise

Energy Resource Planning

Capacity Expansion and Production Cost Modeling

Storage Economics & Dispatch Optimization

Benefit Cost Analysis

Fossil Fuel Retirement Studies

Coal Plant Commitment and Dispatch Analysis

Selection of Relevant Project Experience

Tech Customers

Duke Carbon Plan / 2022

+ Conducted extensive capacity expansion and production cost modeling using EnCompass and presented an alternative proposed portfolio, which results in lower emissions and significantly reduces costs and risks for Duke's ratepayers.

Testimony, Docket E-100, Sub 179

Oregon Public Utilities Commission

Idaho Power IRP Review / 2022

+ Supported the OPUC Staff and Staff Counsel in analysis of the Idaho Power 2021 IRP and crafting of
+ Conducted an in-depth investigation of the inputs, assumptions, and modeling choices in Idaho Power's IRP analysis and summarized findings to support the preparation of Staff comments.

Southwest Energy Efficiency Project

IRP Analysis and Impact Assessment / 2020 - Present

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Led the technical analysis and utilized a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRP.

Arizona Energy Rules Analysis
Summary of Alternative Resource Plan Analysis for Arizona Public Service
Summary of Alternative Resource Plan Analysis for Tucson Electric Power

California Energy Storage Alliance

Long Duration Energy Storage Special Project / 2020

- Supported the technical analysis assessing the needs and benefits of long-duration storage in California. The analysis was based on the use of capacity expansion modeling; results and recommendations were used to identify specific policy opportunities with the CPUC, CAISO, and CEC to advance long-duration storage evaluation and procurement.

Long Duration Energy Storage for California's Clean Reliable Grid

Selection of Relevant Project Experience (continued)

Sierra Club

Alternative Resource Plan for Salt River Project's Integrated System Plan /2022 - Present

+ In anticipation of the SRP Integrated System Plan, provided technical support by preparing a comprehensive analysis of the SRP portfolio options.
+ Conducted EnCompass modeling including capacity expansion modeling to identify the least cost of resources to meet SRP's projected load, and hourly production cost modeling to assess the performance, cost, and emissions of the portfolios.

Report

PacifiCorp IRP Technical Support / 2021 - Present

+ Provided technical support for Sierra Club in analyzing issues of interest during PacifiCorp's IRP stakeholder input process.
+ Reviewed in detail PacifiCorp's IRP modeling to identify inputs and assumptions that might lead the model to deviate from a least cost solution.
+ Supported the development of technical comments before the Oregon Public Utility Commission.

Public Service of Colorado 2021 Energy Resource Plan / 2021

+ Conducted extensive EnCompass modeling including capacity expansion and production cost runs to evaluate alternative retirement dates for the utility's coal units.

Testimony

Clean Energy Group

Alternatives to a natural gas peaking unit / 2021

+ Developed an analysis of a proposed natural gas peaking unit and potential alternatives, including energy storage and market options. The analysis included an energy storage dispatch model in the energy and ancillary services markets of ISO-NE, and an economic comparison with operating the natural gas unit.

Assessment of Potential Energy Storage Alternatives for Project 2015A in Peabody, Massachusetts

Selection of Relevant Project Experience (continued)

Pennsylvania Department of Environmental Protection

Pennsylvania Energy Storage Assessment / 2021

+ Developed analysis and recommendations for measures to foster energy storage investment and integration, including convening a statewide storage issues forum, designating public funding to accelerate storage deployment, establishing incentive programs for storage projects, and accelerating microgrid deployment at critical facilities.

Report

Virginia Department of Mines, Minerals, and Energy

Virginia Energy Storage Study / 2019

+ Developed and used custom modeling tools to estimate the benefit of storage both in front of the meter and behind the meter configurations. Studied energy storage revenue streams to evaluate the technology's potential in the Commonwealth

Report

Sacramento Municipal Utility District

Virtual net metering tarriff design and analysis / 2021 – Present

+ Supported SMUD in outlining a VNEM tariff framework and constructed a financial model to evaluate the customer value proposition for the proposed tariffs, as well as a comparative look at other California IOUs' VNEM program offerings.

• Expert Testimony

- Colorado Public Utilities Commission, Proceeding No. 21A-0141E, Testimony
- North Carolina Utilities Commission, Docket E-100, Sub 179 Testimony
- Michigan Public Utilities Commission, Case U-21193, Testimony
- Public Service Commission of South Carolina, Docket No 2023-1-E Testimony
- Public Service Commission of South Carolina, Docket No 2023-2-E Testimony

Docket No. UE 420

Exhibit SC/103

Witnesses: Ed Burgess and Maria Roumpani

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/103
Public Data Request Responses in UE 420

Sierra Club Data Request 1.16

Refer to the table on PAC/200 at Owen/17:10 and the Third Amendment to the Bronco Coal Supply Agreement for Hunter Plant fuel supply.

(a) Are the volumes associated with the Bronco CSA third amendment subject to minimum take requirements?

(b) Please provide support for any analysis conducted to determine the appropriate minimum take volumes associated with the Bronco CSA and its subsequent two amendments.

(c) Please provide all analysis used to determine the favorability of the Bronco CSA third amendment.

(d) Why was Bronco not held to its contract to continue supply coal under the adjusted price from the 2nd amendment through 2024?

Response to Sierra Club Data Request 1.16

(a) Yes.

(b) The original coal supply agreement (CSA) analysis was provided in Docket No. UE 390. The first amendment to the CSA did not change any commercial terms to the contract, therefore no additional analysis was necessary. The analysis for the second amendment to the CSA was provided with the highly confidential direct testimony of Company witness, James Owen, specifically Highly Confidential Exhibit PAC/204.

(c) This analysis was filed in this proceeding on May 8, 2023.

(d) Please refer to Mr. Owens' direct testimony, Exhibit PAC/200 at Owen/16:15 – 17:2, which describes why Bronco was not held to its contract to continue supply coal under the adjusted price from the second amendment through 2024.

Sierra Club Data Request 1.19

Please refer to Confidential Table 6 on PAC/200 at Owen/26.

(a) Please explain how the quantities and prices of each coal supply were determined given the fact that PacifiCorp had not completed its 2023 LTFSP for Jim Bridger at the time of its application in this proceeding.

(b) Please explain whether the quantities and prices will be updated, along with the overall 2024 NPC estimates, once the 2023 LTFSP is completed.

(c) Please provide a comparison of the quantities and prices of each Jim Bridger coal supply assumed in the 2024 TAM and those in the 2022 LTFSP and explain any discrepancies.

(d) Please explain which coal fuel price or prices were used for Jim Bridger as an input to PacifiCorp's production cost modeling in Aurora to calculate the 2024 NPC. If multiple pricing tiers were used, please provide a detailed explanation of how these parameters were set and whether any minimum quantities were assumed.

(e) Please explain why PacifiCorp assumed a new contract would be executed to supply coal from Black Butte in 2024. Please reconcile this with PacifiCorp's 2022 LTFSP.

(f) Please provide any supporting analysis for the price and quantity assumed for Black Butte coal supply in 2024 (and beyond), including any supporting work papers.

Response to Sierra Club Data Request 1.19

(a) The available quantities and prices were determined based on forecast assumptions, conversations with Black Butte, and market price projections. The generation results of the Aurora model then determined the quantities to be provided by each source.

(b) As stated in the Company's response to Sierra Club Data Request 1.6, PacifiCorp recently finalized the Jim Bridger 2023 Long-Term Fuel Plan (LTFP) on May 31, 2023 and provided it to Parties in this proceeding. The 2023 LTFP helps inform the preferred resource mix going forward, and the Company's 2024 transition adjustment mechanism (TAM) reply filing will include any updates to the quantities and prices resulting from the finalized 2023 LTFP.

(c) PacifiCorp objects to this request as unduly burdensome, outside the scope of the proceeding, requesting the development of new study or information, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

Prices and quantities assumed from different coal sources are frequently updated with changes to forecasts, indices, market conditions, etc. The 2022 LTFP was filed in Docket UE 400 on April 15, 2022, so changes when comparing to the 2024 transition adjustment mechanism (TAM) would be as a result of these updates. In addition, as stated in the Company's response to subpart (b) above, and in the Company's response to Sierra Club Data Request 1.6, the 2024 TAM reply will include updates based on the results of the 2023 LTFP.

(d) Please refer to the Company's response to TAM Support Set 1 (concurrent confidential work papers); specifically confidential file "_OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF.xlsx", tab "Coal Expense Calculation". Please refer to the Company's responses to Sierra Club Data Request 1.5 and Sierra Club Data Request 1.6 which provide a description of how the minimum quantities were determined. The Bridger Coal Company (BCC) base plan costs include all forecasted costs for the mine, including the operation of one dragline. The supplemental coal pricing is based on the forecasted incremental cost of operating a second dragline for increased levels of coal production. The pricing for deliveries from Black Butte was developed based on conversations with Black Butte and market price projections.

(e) Please refer to the Company's response to subpart (c) above.

(f) Pricing and volumes were based on conversations with the supplier, management's professional judgement, and estimates for the assumed contract volumes as shown in the work papers.

Sierra Club Data Request 1.5

CONFIDENTIAL BEGINS - The 2024 TAM assumes that [redacted] base tons are delivered from the Bridger Coal Company (BCC) mine plan. Please explain the process and assumptions leading to the creation of this number.

Response to Sierra Club Data Request 1.5

The base delivered tons assumed for Bridger Coal Company (BCC) is based on the estimated production level in the mine plan when operating one dragline. The operation of one dragline is considered the minimum prudent operating level to preserve a skilled workforce necessary to comply with statutory final reclamation requirements. Any lower level of production increases the production cost per ton of coal, reduces the efficient use of customers' investment in BCC, and harms customers.

Sierra Club Data Request 1.22

CONFIDENTIAL REQUEST - Please refer to PAC/200 at Owen/26:5-6, which states that "The lower volume results in fixed mining costs being allocated to fewer tons, thus raising the cost per ton delivered."

(a) Please identify what portion of the total 2024 BCC coal costs (i.e., [redacted]]) are considered fixed. Please provide any supporting work papers.

(b) Please identify the date when each of these fixed costs were first incurred.

(c) Please identify any actions PacifiCorp took over the last 3 years to avoid incurring these fixed costs.

Response to Sierra Club Data Request 1.22

(a) PacifiCorp objects to this request as unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding this objection, PacifiCorp responds as follows:

PacifiCorp prepared an analysis of Bridger Coal Company's (BCC) fixed costs for the 2023 Long-Term Fuel Plan (LTFP). While this analysis was not based on the mine plan data in the 2024 transition adjustment mechanism (TAM), it is sufficiently similar to represent the portion of costs that are considered fixed. Please refer to Confidential Attachment SC 1.22.

(b) BCC does not maintain a history of fixed costs, but fixed costs have been incurred since the mine first opened in 1974.

(c) PacifiCorp actively engages in comprehensive management of both fixed and variable costs and in oversight of BCC's operations. PacifiCorp works closely with BCC personnel to ensure the mine operates safely and production and cost targets are achieved. For example, PacifiCorp: (1) coordinates daily calls between BCC, PacifiCorp fuel resources employees, Idaho Power Company (IPC), and Jim Bridger plant employees to inform coal delivery and quality requirements and minimize coal handling activities (daily, weekly, monthly, and annual targets discussed); (2) reviews daily production cost reports to measure performance on a real-time basis; (3) reviews monthly performance reports to ensure targets are achieved and areas requiring course correction are identified; (4) includes BCC in corporate alliances to achieve greater volume discounts where applicable; (5) requires PacifiCorp approval prior to hiring new employees; (6) requires evaluations and approvals for capital expenditures; and (7) attends Management Committee Meetings with IPC and BCC representatives on a quarterly basis to evaluate and direct mine activities.

UE-420 / PacifiCorp
June 1, 2023
Sierra Club Data Request 1.13

Sierra Club Data Request 1.13

> **CONFIDENTIAL REQUEST** - Please refer to the Hunter tab on CONF FUELLIGHTS-ALL 2024 TAM Directv4.xlsx, which lists the Coal Dollars/Ton received as [redacted] and Total Dollars/Ton Received [redacted]. Please also refer to the table on Pac/200 at Owen/15, listing the 2024 price per ton for the Gentry CSA as [redacted]. Please explain the discrepancy between and the origins of each of these numbers.

Response to Sierra Club Data Request 1.13

> The price reflected in the table in Exhibit PAC/200 Owen/15 is correct. The amount in the work papers is out of date and will be updated with the Company's transition adjustment mechanism (TAM) reply filing.

OPUC Data Request 36

CONFIDENTIAL REQUEST - Hunter Coal - Please provide the following information regarding the Wolverine/Sufco, Skyline contract for Hunter in Confidential Table 1 on PAC/200, Owen/21:

(a) the price and quantity by year,

(b) the quantity and price of any minimum take agreement, and

(c) an explanation of why this is categorized as a [redacted] in Confidential Table 1.

Confidential Response to OPUC Data Request 36

(a) The delivered price for 2024 is [redacted].

(b) [redacted].

(c) As mentioned in the Company's response to subpart (b) above, [redacted].

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

Sierra Club Data Request 2.3

CONFIDENTIAL REQUEST - Please refer to OR UE-420 ORTAM24 Mitchell - - Direct Mar 2023 CONF.xlsm.

(a) From the ResourceMonth tab, please explain the source of the values in Column I (Full_Load_Cost), Column J (Dispatch_Cost), Column K (Net_Cost), and Column L (Incr_ Cost), including a description of analyses, inputs, and assumptions and provide all relevant input and output data, in spreadsheet format.

(b) From the Coal Expense Calculation tab, please explain why [redacted].

(c) Please explain the calculation of the Monthly Fixed Costs (Column R), including inputs incorporated into the calculation. If already provided in the work papers, please identify which work paper and the location of the supporting information.

(d) Were the Monthly Fixed Costs included in PacifiCorp's production cost modeling in AURORA to calculate the 2024 NPC?

i. If so, how were they incorporated into the modeling?

ii. If not, which pricing tiers were included in the modeling?

Response to Sierra Club Data Request 2.3

Referencing confidential work paper "OR UE-420 ORTAM24 Mitchell - - Direct Mar 2023 CONF.xlsm", the Company responds as follows:

(a) These are reported values from Aurora's in-model, constrained least-cost optimization. Inputs are the set of all modeling parameters. Analyses are the model runs themselves. For input assumptions, please refer to all the work papers provided with the Company's response to TAM Support Set 2 (5-Business Day). For output data, please refer to the Company's response to TAM Support Set 1 (concurrent work papers), specifically confidential net power costs (NPC) report "_OR UE-420 ORTAM24 Mitchell - - Direct Mar 2023 CONF.xlsm".

(b) Tier 0 costs (referenced in column R; cells R6-R13) are applied in calculating costs in cells D96:O117.

(c) Please refer to the Company's response to TAM Support Set 2 (5-Business Day work papers), specifically file "Aurora GN Fuel Prices", tab "Coal Costs 2024" for the source data on monthly fixed costs that are noted in as Monthly Fixed Costs (column R) in the NPC report. These costs are calculated by dividing the annual fixed costs components of the coal contract by a factor of 12000.

(d) The "Monthly Fixed Costs" are fixed at the moment of forecast and do not affect the optimization modeling in Aurora. All variable components of all pricing tiers are included in the modeling.

Sierra Club Data Request 1.12

HIGHLY CONFIDENTIAL REQUEST - Refer to PAC/200 at Owen/17 describing the change in price for delivered coal from [redacted] to Hunter.

(a) Was the [redacted] contract amended for the 2024 TAM?

(b) Please provide all analysis and documents that support changes to the [redacted] contract.

Response to Sierra Club Data Request 1.12

(a) No. A new contract is currently being negotiated. The assumed pricing is based on current discussions with the supplier and may be updated if or when a contract has been executed.

(b) Supporting analysis will be provided once the contract has been completed and based on the schedule / guidelines established for transition adjustment mechanism (TAM) filings.

UE 420 / PacifiCorp
May 18, 2023
OPUC Data Request 39

OPUC Data Request 39

Hunter RFP Analysis and Eagle Butte CSA - In the Hunter RFP analysis described in the work paper "Hunter RFP Analysis by Bid Number_2022 11 29 HIGHLY CONF FINAL", please provide a description of the coal contract assumptions and inputs used in each of the scenarios. For each scenario:

(a) Which Hunter coal contracts were hard coded as assumptions into the model? What were their prices and quantities in each year?

(b) Which coal contracts or sport purchase options were available for selection by the model? What were their prices and available quantities in each year?

(c) Is there any other information or context important to understanding how the hard-coded and selectable options for Hunter coal supplies were assessed in the Hunter RFP Analysis?

Highly Confidential Response to OPUC Data Request 39

Referencing the highly confidential work papers supporting the direct testimony of Company witness, James Owen, specifically highly confidential folder "Coal Supply HIGHLY CONF", highly confidential file "Hunter RFP Analysis by Bid Number_2022 11 29 CONF FINAL". The Company responds as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

For details on the incremental coal supply options in each case, including quantity, price, and heat content, please refer to highly confidential file "Hunter RFP Analysis by Bid Number_2022 11 29 CONF FINAL" and the contract details starting on the following rows on tab "Bids":

[redacted]

[redacted]

[redacted]

(a) Please refer to the summary of modeling details provided above and highly confidential "Hunter RFP Analysis by Bid Number_2022 11 29 CONF FINAL".

(b) The Company assumes that the reference to "sport purchase option" is intended to be a reference to spot purchase option. Based on the foregoing assumption, the Company responds as follows:

No coal contracts were selected by the model. The Company evaluated the specified combinations of bids described above. With regard to [redacted] starting in row 55 of tab "Bids" in highly confidential file "Hunter RFP Analysis by Bid Number_2022 11 29 CONF FINAL".

(c) Referencing Mr. Owen's direct testimony, specifically Highly Confidential Exhibit PAC/201 (Hunter/Gentry CSA Analysis), the Company responds as follows:

The bid under consideration in Highly Confidential Exhibit PAC/201 was evaluated assuming other coal options were also secured, even though those options were still under negotiation at that time. [redacted]

Highly confidential information is designated as Protected Information under the Modified Protective Order No. 23-120 and may only be disclosed to qualified persons as defined in that order.

UE 420 / PacifiCorp
May 18, 2023
OPUC Data Request 28

OPUC Data Request 28

> **Hunter Coal Supply -** Please provide the quantity and price of coal by year for the Bronco Agreement, the Second Amendment to the Bronco Agreement, and the Third Amendment to the Bronco Agreement.

Confidential Response to OPUC Data Request 28

The original contract established the following quantity and price terms:

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

Docket No. UE 420

Exhibit SC/104

Witnesses: Ed Burgess and Maria Roumpani

CONFIDENTIAL

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/104
Confidential Data Request Responses in UE 420

This exhibit is confidential pursuant to Protective Order 16-128

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS SEPARATELY PROVIDED TO THE COMMISSION AND ELIGIBLE PARTIES

Docket No. UE 420

Exhibit SC/105

Witnesses: Ed Burgess and Maria Roumpani

HIGHLY CONFIDENTIAL

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/105
Highly Confidential Data Request Responses in UE 420

This exhibit is highly confidential pursuant to
Modified Protective Order No. 23-11

THIS EXHIBIT IS HIGHLY CONFIDENTIAL IN ITS ENTIRETY AND IS SEPARATELY PROVIDED TO THE COMMISSION AND ELIGIBLE PARTIES

Docket No. UE 420

Exhibit SC/106

Witnesses: Ed Burgess and Maria Roumpani

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/106
Public Data Request Responses from Docket No. A.21-08-004 (Cal. Pub. Utils. Comm'n)

Sierra Club Data Request 2.10

Has PacifiCorp considered other mechanisms for recovering reclamation costs for the Bridger mine outside of the ECAC, or similar fuel adjustment clauses in other states?

Response to Sierra Club Data Request 2.10

No. As reclamation costs are incurred costs by the Bridger Mine in the mining of coal, these costs are properly included in the fuel costs for Bridger coal burned at the Jim Bridger plant and therefore properly included in net power costs (NPC) mechanisms, such as the energy cost adjustment clause (ECAC) NPC mechanism in California.

Docket No. UE 420
Exhibit SC/107
Witnesses: Ed Burgess and Maria Roumpani

HIGHLY CONFIDENTIAL

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/107

Highly Confidential Jim Bridger 2023 Long-Term Fuel Supply Plan

This exhibit is highly confidential pursuant to
Modified Protective Order No. 23-211

THIS EXHIBIT IS HIGHLY CONFIDENTIAL IN ITS ENTIRETY AND IS SEPARATELY PROVIDED TO THE COMMISSION AND ELIGIBLE PARTIES

Docket No. UE 420
Exhibit SC/108
Witnesses: Ed Burgess and Maria Roumpani

Opening Testimony of Ed Burgess and Maria Roumpani
On Behalf of Sierra Club

Exhibit SC/108

Public Jim Bridger 2023 Long-Term Fuel Supply Plan

PACIFIC POWER.
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

May 31, 2023

VIA ELECTRONIC FILING

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

Re: LC 82—PacifiCorp's Jim Bridger Long-Term Fuel Plan

In accordance with Order No. 23-131 issued in docket LC 82 on April 6, 2023, PacifiCorp d/b/a Pacific Power hereby submits for filing its Jim Bridger Long-Term Fuel Plan (LTFP).

The Jim Bridger LFTP contains highly commercially sensitive, non-public information related to PacifiCorp's fueling strategy at the facility. As a result, PacifiCorp classifies the Jim Bridger LTFP as containing both confidential and highly confidential information and provides it in accordance with the General Protective Order No. 16-128 and Modified Protective Order 23-120 in Docket No. UE 420, and General Protective Order 23-132 for Docket No. LC 82. A Revised Motion for Modified Protective Order in Docket LC 82 was filed on May 26, 2023, and an order is pending.

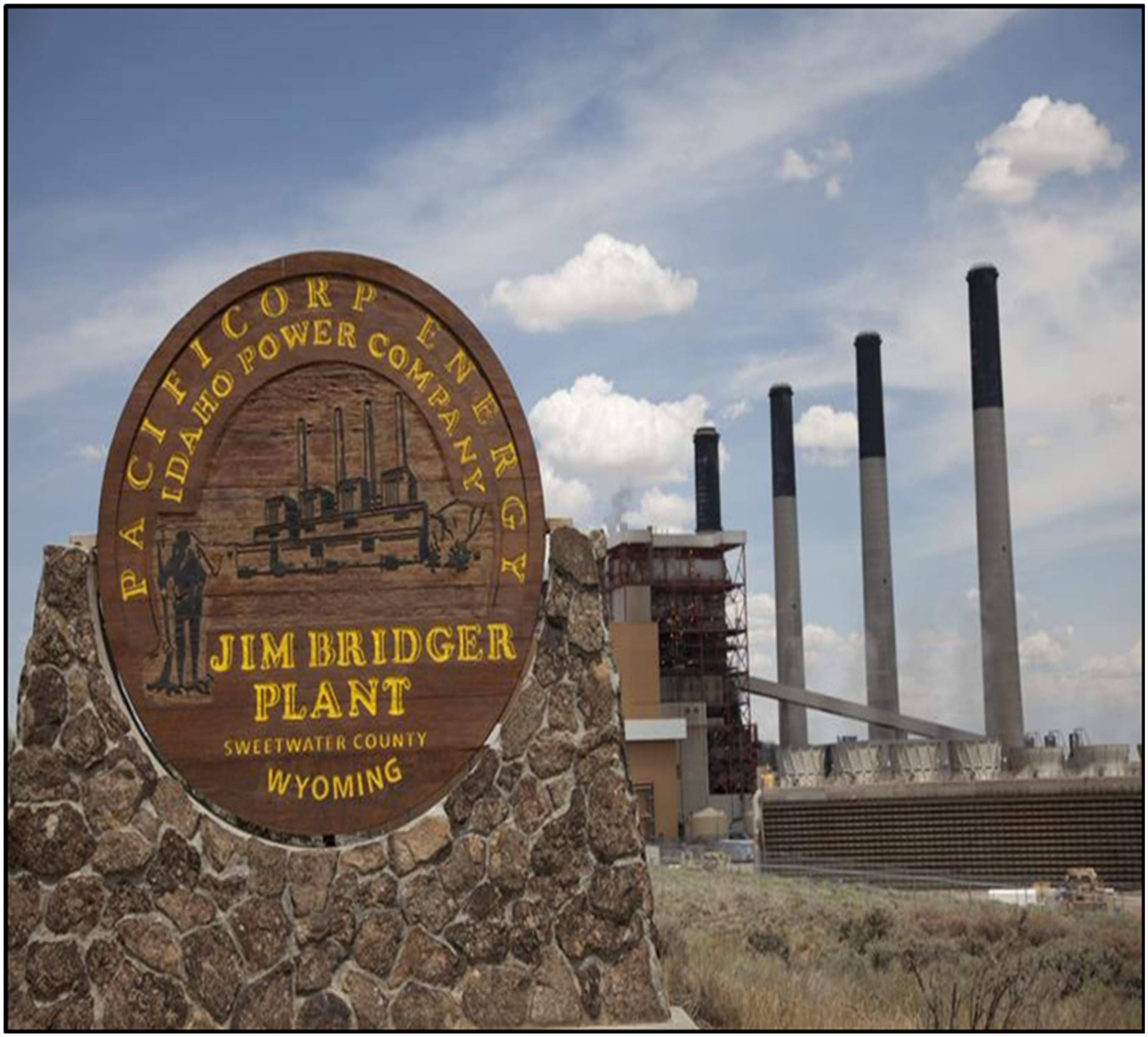
Please direct any inquiries about this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosure

cc: UE 420



PACIFICORP HIGHLY CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT

May 31, 2023

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

1 INTRODUCTION AND EXECUTIVE SUMMARY

In PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, the Public Utility Commission of Oregon (Oregon Commission) adopted PacifiCorp's proposal to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives for the Jim Bridger Power Plant.[1] As set forth in PacifiCorp's compliance filing in the 2015 TAM, Docket UE 287, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, risk-adjusted coal supply evaluated on a multi-year basis. The long-term fuel plan is designed to ensure that fuel supplies are fair, just, and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

PacifiCorp has previously filed long-term fuel plans in December 2015, March 2018, and April 2022. After the Company filed the 2018 Fuel Plan, the Oregon Commission directed PacifiCorp to develop an alternative analysis using a shortened plant life of January 1, 2030, instead of December 31, 2037, to comply with Oregon Senate Bill (SB) 1547 signed in 2016. PacifiCorp refreshed the 2018 Fuel Plan in March 2019 to evaluate the reasonableness of the Company's fueling strategy for the Jim Bridger plant using the shortened plant life. The 2023 Fuel Plan is consistent with Oregon SB 1547 as it contemplates consuming coal through 2029, in conformity with PacifiCorp's 2023 Integrated Resource Plan (IRP).

In the October 2021 final order in PacifiCorp's 2022 TAM, the Oregon Commission required PacifiCorp to provide an updated long-term fuel plan in 2022 and submit it with the 2023 TAM. In February of 2022, PacifiCorp sought to delay this filing because several events had created significant uncertainty which prevented the Company from definitively determining the least-cost, risk-adjusted coal supply for the Jim Bridger plant at that time.[2] Specifically, those events included actions by the United States Environmental Protection Agency (EPA) around Jim Bridger's regional haze obligations, revised dates for Idaho Power Company's exit from the Jim Bridger plant, and PacifiCorp's commitment to evaluate carbon capture, utilization and sequestration (CCUS) at the Jim Bridger plant.

Recognizing the uncertainties and difficulties, the Oregon Commission required PacifiCorp to file the 2022 Fuel Plan in April 2022 and clarified that the plan did not need to be a final strategy. While the 2022 Fuel Plan was preliminary, it considered the options available to PacifiCorp based on the best information available at the time. The 2023 Fuel Plan has confirmed the findings of the 2022 Fuel Plan and is likewise based on the best available information. Some uncertainties have been resolved in the last year, however uncertainty still exists surrounding many issues including the EPA's establishment of new nitrogen oxides (NOx) emissions budgets under Ozone National Ambient Air Quality Standards (Ozone Transport Rule) in the state of Wyoming, CCUS requirements, and coordination with Idaho Power Company on exit or gas conversion dates.

In the May 2022 final order in PacifiCorp's 2021 IRP Filing, the Oregon Commission directed PacifiCorp "to file an updated long-term fuel plan for Jim Bridger with its 2023 IRP… PacifiCorp agreed with that

[1] *In the Matter of PacifiCorp d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Net Power Costs Approved Subject to Adjustments, Order No. 13-387 (Oct. 28, 2013).
[2] *In the Matter of PacifiCorp d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Motion to Amend Order No. 21-379 (Feb. 11, 2019).

assessment and consented to provide the updated plan with the 2023 IRP"[3] which was released on March 31, 2023. In April 2023, the Oregon Commission extended the deadline to May 31, 2023.[4]

In the October 2022 final order of PacifiCorp's 2023 TAM, the Oregon Commission approved a stipulation where PacifiCorp agreed that "[m]odeling for the Long-Term Fuel Supply Plan will be conducted in a platform able to accept multiple fuel price tiers such as Aurora or PLEXOS. PacifiCorp will include the following scenarios:

i. Scenario that does not assume a minimum take at either the Black Butte or Bridger Mine; *(Refer to Scenario 6 below)*
ii. Scenario evaluating an alternative to the minimum take requirement in the Black Butte coal supply agreement signed in 2022; *(Refer to Scenario 1 below)*
iii. Scenario evaluating early closure of the Bridger mine (before 2028) and fueling Jim Bridger through end of life with stockpiled coal supplies. *(Refer to Scenario 3 below)*"[5]

To develop the 2023 Fuel Plan, PacifiCorp studied, reviewed, and evaluated different fueling options for the Jim Bridger plant. The evaluation of these fueling options provides valuable insight into [redacted] As part of its 2023 IRP, PacifiCorp assessed various long-term coal supply options as well as alternative options for Jim Bridger Units 3 and 4, including retrofit for CCUS, conversion to natural gas and/or other alternative fuels, and early retirement. The 2023 IRP preferred portfolio selected the conversion of Units 3 and 4 to natural gas in 2030 which requires the ending of coal consumption by December 31, 2029.

Within the 2023 Fuel Plan, the Company has presented several different fueling options. The fueling options consider varying delivery schedules sourced from Bridger Coal Company (Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB). Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified delivery schedules. Included in these different mine scenarios are estimated shutdown dates for the Bridger mine.

The 2023 Fuel Plan provides third-party coal supply volume and pricing estimates based upon the current contract and ongoing discussions with the Black Butte mine, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2023 Fuel Plan provides estimated volumes and rail rates for transportation services based on agreements with the Union Pacific Railroad (UPR) for the transport of coal from third-party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are derived from a detailed third-party study completed in 2017 by the engineering and consulting firm Burns & McDonnell, adjusted for inflation and to account for volumes associated with operating two coal units instead of four coal units.

After considering factors influencing the long-term fueling strategy and information available to PacifiCorp at this time, the Company developed and evaluated six Jim Bridger plant coal fueling options:

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[3] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, 2021 IRP Acknowledged with Modifications and Exceptions, Order No. 22-178 (May 23, 2022).
[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Integrated Resource Plan*, Docket No. LC 82, Order No. 23-131 (Apr. 6, 2023).
[5] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Comprehensive Stipulation Adopted: Directives for Future Filings, Order No. 22-389 (Oct. 25, 2022).

- **Scenario 1** [redacted]
- **Scenario 2** [redacted]
- **Scenario 3** [redacted]
- **Scenario 4** [redacted]
- **Scenario 5** [redacted]
- **Scenario 6** [redacted]

As a preliminary indication of the cost-effectiveness of the proposed scenarios using recent assumptions, the Company completed a Present Value Revenue Requirement (PVRR) calculation, comparing major components of PacifiCorp's system costs resulting from the various fueling options, including a composite ranking considering both financial and risk weighting. These costs include coal purchases, natural gas purchases, and system power purchases offset by wholesale power sales (System Costs). Other components not considered in the analysis include costs associated with qualifying facilities, power purchase agreements, geothermal and wheeling. These items do not vary with system dispatch in the PLEXOS model and would not vary between scenarios. This analysis is based on the Company's forward price curve for power and natural gas, which does not include greenhouse gas costs, but does account for the impacts of certain recently proposed EPA emissions requirements, such as the Ozone Transport Rule. The results of the PVRR analysis and risk evaluation indicate that Scenario 5 and Scenario 6 are the current least-cost, risk-adjusted options. Option 6 was modeled assuming no minimum take-or-pay obligations for the Bridger mine or Black Butte Coal Company. Based on PacifiCorp's evaluation using the PLEXOS model, all of the available incremental coal from the Bridger mine would be cost-effective. As a result, the fueling plans in Scenario 5 and Scenario 6 are essentially the same. Therefore, Scenarios 5 and 6 will be referred to as the "Preferred Scenario" in this report going forward.

The benefits of pursuing the Preferred Scenario as the long-term fueling strategy for the Jim Bridger plant include the following:

- Provides the least-cost, risk-adjusted fuel supply for the Jim Bridger plant,
- [redacted]
- [redacted]
- [redacted]

Although the Preferred Scenario is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant, taking into consideration both cost and risk, and will update the long-term fuel supply plan after each IRP is released to reflect changing assumptions and expectations.

2 EVALUATION METHODOLOGY

In the 2023 Fuel Plan, PacifiCorp evaluated several different fueling options for the Jim Bridger plant. The methodology used to evaluate the fueling options is similar to the methodology used in the April 2022 long-term fuel plan. As noted above, the 2023 Fuel Plan considers the variable components of PacifiCorp's System Costs. The same production software used in the 2023 Integrated Resource Plan (IRP), PLEXOS, was used for the 2023 Fuel Plan. Prior plans used PacifiCorp's Generation and Regulation Initiative Decision Tools model (GRID) and costs for the consumed tons required to support the generation forecast under each fueling option were then calculated. The cost of coal for the Jim Bridger plant under each fueling option was then compared to the system benefits of incremental coal-fired generation from the PLEXOS model on a PVRR basis.

3 BACKGROUND

The Jim Bridger plant is a coal-fired plant located in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of Rock Springs, Wyoming.

The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7%) and Idaho Power Company (Idaho Power) (33.3%). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Over the four-year period of 2019-2022, the Jim Bridger plant consumed approximately 24 million tons of coal, an average of six million tons per year. The plant is designed to consume coal sourced from southwest Wyoming with heat content in the range of 9,000 Btu/lb. to 10,000 Btu/lb.

The Bridger mine is located adjacent to the Jim Bridger plant. Having ceased underground mining operations in December 2021, the Bridger mine currently consists solely of surface mining operations. Like the Jim Bridger plant, the Bridger mine is jointly owned by PacifiCorp (66.7%) and Idaho Power (33.3%). The surface mine is a combination dragline and truck/loader operation that produces approximately [redacted] million tons of coal per year.

For regulatory purposes, the Bridger mine is consolidated with PacifiCorp's operations. PacifiCorp's share of the Bridger mine is included in the PacifiCorp rate base and its share of mining costs, including depreciation and depletion, is included in System Costs.

In addition to the Bridger mine deliveries, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements from the nearby Black Butte mine. The UPR provides rail access for all the coal delivered from the Black Butte mine to the plant.

4 ASSUMPTIONS

Currently, the Jim Bridger plant has three potential sources for coal supply:

- The Bridger mine
- The Black Butte mine

- Wyoming's SPRB mines

As demand for generation from the Jim Bridger plant is expected to decline significantly after Units 1 and 2 convert to natural gas in 2024, the 2023 Fuel Plan examines scenarios ranging from [redacted]

To assist with the characterization of the potential supply changes over time, the fueling options have been separated into "near-term" and "long-term" periods for discussion purposes. For purposes of the 2023 Fuel Plan, the near-term period has been defined as 2023 and corresponds to the time that Units 1 and 2 are consuming coal before the conversion of those units to gas operation. The key assumptions in the 2023 Fuel Plan are explained below:

4.1.1 Generation

As mentioned above, generation forecast assumptions are provided by PacifiCorp's PLEXOS model for each fueling option studied. To ensure compliance with the Regional Haze Consent Decree with the State of Wyoming, the 2023 Fuel Plan assumes Jim Bridger Units 1 and 2 will stop consuming coal December 31, 2023, and convert to natural gas in 2024. Consistent with the outcome of the 2023 IRP, Jim Bridger Units 3 and 4 will continue to consume coal until December 31, 2029, and then also convert to natural gas in 2030.

On a total plant basis (i.e., including Idaho Power's expected consumption), coal consumption is forecast to be in the range of [redacted] million to [redacted] million tons for 2023.

4.1.2 Plant Depreciable Life

The assumed depreciable life in Oregon of PacifiCorp's share of the Jim Bridger plant extends through 2029 for Units 1 and 2 and through 2025 for Units 3 and 4. Other states in PacifiCorp's service territory use differing depreciable lives for different units ranging from 2023 to 2037, based upon PacifiCorp's 2018 depreciation study and other regulatory agreements.

4.1.3 Bridger Mine Plans

In early 2023, the Bridger mine prepared three operating mine plans; [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.1.4 Third Party Coal

Due to the geographic location of the Jim Bridger plant, economic fuel supply alternatives other than the Bridger mine are limited to one additional operating mine located in southwest Wyoming and the SPRB mines of Campbell County, Wyoming.

The Black Butte mine, located 20 miles southeast of the Jim Bridger plant, is operated by Lighthouse Resources Inc. (Lighthouse). Lighthouse emerged from bankruptcy in 2020. The mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck/loader fleet. In recent years, the mine has produced less than [redacted] tons per year and the Jim Bridger plant has been the mine's primary customer. Between 2019 and 2022 the Jim Bridger plant received approximately [redacted] tons, an average of [redacted] tons per year, from the Black Butte mine. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with UPR.[6]

The Powder River Basin is the largest coal mining region in the United States. Coal from the SPRB is classified as sub-bituminous coal. SPRB coal contains an average heat content of approximately 8,800 Btu/lb. The coal mined in the SPRB is low sulfur and low ash. Due to its unique quality characteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In 2022, there were seven mining companies operating twelve active mines in Wyoming's Powder River Basin, producing roughly 238 million tons. SPRB mines contain the highest heat content coal in the basin ranging between 8,600 Btu/lb. and 8,950 Btu/lb. These mines are located about 550 miles from the Jim Bridger plant. SPRB mines and the Jim Bridger plant are served by UPR. Consumption of SPRB coal requires UPR delivery.

4.1.5 Black Butte Pricing

As of May 2023, coal from the Black Butte mine is purchased under a Coal Supply Agreement (CSA) signed June 19, 2022, that ends December 31, 2023. [redacted]

[6] Due to limited coal reserves, estimated production costs, transportation difficulties, and the planned closure of the Naughton plant in 2025, Kemmerer Operations, LLC's Kemmerer mine is not considered a viable fuel source for the Bridger plant.

[redacted]

4.1.6 Black Butte Mine Volume

PacifiCorp conducted a high-level review of the Black Butte mine coal resource and reserve estimates in 2015. The study consisted of reviewing available third-party Black Butte reserve and geology documents, along with Black Butte's geology information and permitting status. At the time, based on the information reviewed, the conclusion of the review was that the Black Butte mine had [redacted] tons that could be considered economic coal reserves under the terms and conditions of the then-current contract.

PacifiCorp and Idaho Power purchased 14 million tons between 2016 and 2022. The scenario that consumes the highest volume of Black Butte coal, assumes purchases of [redacted] tons by PacifiCorp and Idaho Power between 2023 and 2029. Therefore, this study assumes that Black Butte has sufficient coal reserves to satisfy the Jim Bridger plant. Note that the reserve estimate includes the expansion of Black Butte mine into the Pit 15 area. As of May 2023, the permitting process for this area is still pending with federal government agencies. If Pit 15 is not permitted, the risk exists that sufficient reserves may not be available from the Black Butte mine under [redacted]

4.1.7 Assumed SPRB Coal Pricing

Coal pricing for 2023 comes from a coal supply agreement with [redacted]. Volumes purchased by PacifiCorp range from [redacted]. SPRB coal pricing in the 2023 Fuel Plan beyond 2023 is based on a long-term coal forecast published by EVA in spring 2023.

4.1.8 Powder River Basin Coal in the Near-Term

Powder River Basin coal has a high propensity to spontaneously combust and is the most friable coal type consumed in the power industry. While major plant modifications would be required to receive and consume large volumes of SPRB coal safely and reliably at the Jim Bridger plant, currently the plant is likely capable of consuming SPRB coal on a limited scale without major modification to the plant's coal unloading or coal consuming infrastructure. For example, in a test during 2015, the plant handled and consumed 10 trains totaling 140,540 tons of SPRB coal. Based on knowledge gained from that test and PacifiCorp's professional judgment, PacifiCorp believes that up to a total of 800,000 tons of SPRB coal per year can be safely and reliably consumed without major modifications to the plant infrastructure. This estimate is considered aggressive, as issues with scheduling or handling coal could result in lower maximum annual SPRB volumes using the existing infrastructure. The current 800,000-ton assumption could be adjusted based upon the results of actual coal deliveries in 2023 from the [redacted]

4.1.9 Transportation

Coal from the Bridger mine is delivered to the Jim Bridger plant via conveyor belt, and the cost of conveying the coal is included in the delivered coal cost. The Jim Bridger plant is also connected by a rail spur to the UPR mainline track. UPR has the trackage rights to the mainline and spur to the Jim Bridger plant and, as a result, the Jim Bridger plant is captive to UPR for deliveries by rail. Deliveries from all sources other than the Bridger mine are assumed to be delivered by the UPR. As mentioned above, the transportation rates for delivery of Black Butte and SPRB coal are based upon the current rail transportation agreement with UPR and escalated beyond 2023.

4.2 Jim Bridger Plant Capital

PacifiCorp selected the consulting firm Burns & McDonnell (B&M) to perform an independent capital evaluation of the plant modifications and capital expenditures required at the Jim Bridger plant to consume volumes, up to 100%, of SPRB coal. B&M completed a comprehensive study in June 2017. The study outlined high priority plant modifications and the estimated costs in converting the Jim Bridger plant's main fuel source to SPRB coal. The study focused on required modifications to several systems including coal handling and storage, rail delivery, mechanical process/power island, electrical, substation and overhead distribution and air permitting.

The required coal handling system modifications identified engineering controls that would be needed and relied upon to reduce and mitigate coal dust throughout the coal handling system. The study emphasized the importance of having adequate wash down capability by installing and utilizing fixed pipe wash down systems in existing coal reclaim and conveyor tunnels, crusher houses, tripper bays and in the rail unloading hopper facilities. The study also assumed a loop track and thaw shed would be required. Recommendations were made on how to safely and reliably handle SPRB coal: keep areas clean, eliminate ignition sources and detect spontaneous combustion with accumulated SPRB coal dust. These safety steps are designed to protect people, equipment, and enclosures from explosions due to the dangerous spontaneous combustion tendencies of SPRB coal.

Required modifications to the rail delivery system outlined in the 2017 study indicate that the current unloading configuration is [redacted]

In the 2023 Fuel Plan, the capital modifications for [redacted] The 2023 Fuel Plan assumes that Idaho Power will participate in the capital modifications. PacifiCorp's estimated cost of the capital modifications based on B&M's June 2017 study is approximately [redacted], as provided in Table 1.

TABLE 1
Jim Bridger Plant Capital Costs

[redacted]

5 FUEL SUPPLY MIX

PacifiCorp evaluated six fueling scenarios for the Jim Bridger plant for the 2023 Fuel Plan. Those scenarios are described below. Please refer to Appendices 1-13 for detailed fueling mix and pricing information for each fueling option considered. Summaries of the fuel supply mix, including average volumes for the near-term and long-term, for each fueling option evaluated are provided below. Note that Scenarios 5 and 6 result in the same solution but were run in PLEXOS with different assumptions as seen below.

5.1 SCENARIO 1 [redacted]

Scenario 1 considers [redacted]

5.2 Scenario 2 [redacted]

Scenario 2 considers [redacted]

5.3 Scenario 3 [redacted]

Scenario 3 considers [redacted]

5.4 Scenario 4 [redacted]

Scenario 4 considers [redacted]

5.5 Scenario 5 [redacted]

Scenario 5 considers [redacted]

5.6 Scenario 6 [redacted]

Scenario 6 considers [redacted]

6 PVRR ANALYSIS AND RESULTS

6.1 Jim Bridger Coal Fueling Cost Analysis

The PVRR analysis represents a present value revenue requirement using major NPC components for the PacifiCorp system. The fuel costs for all coal and gas plants are included along with power purchase costs offset by power sales revenues. Scenario 2 [redacted] The PVRR results have been discounted using PacifiCorp's weighted average cost of capital. A total PVRR differential has been calculated for each of the six fueling scenarios comparing the total PVRR for each option against the Preferred Scenario, the fueling option with the lowest PVRR dollar amount.

Table 2 below shows the results of the PVRR analysis for each fueling option in the 2023 Fuel Plan supplying the Jim Bridger plant with coal through December 2029. Also included in Table 2 is a financial ranking from 1 to 6 for each of the fueling options. Table 2 also shows the Preferred [redacted] The other fueling options range between these options. Additional discussion on risk assessment for each fueling option is presented in the next section below.

TABLE 2
PVRR Analysis Through December 2029

[redacted]

6.2 Risk Analysis

The following table provides a risk assessment for each scenario and outline the specific categories that have been considered in the risk evaluation analysis. Table 3 illustrates a risk assessment of Scenarios 1 through 6 through December 2029.

TABLE 3
Risk Evaluation Through 2029

[redacted]

The defined risk profile categories include (1) Incremental Capital – the risks associated with the total costs of incremental capital expenditures related to each fueling scenario, (2) Coal Market – risks associated with adequate coal supplies, as well as coal and transportation price, (3) Power and Natural Gas Market Volatility – risks associated with power market price volatility driven by changing natural gas prices, availability of hydro generation, impacts of renewable energy sources, load demand, and (4) Jim Bridger Plant Environmental Compliance – risks associated with new environmental regulations that could change generation at the Jim Bridger plant.

For each fueling scenario under each risk category, a number ranging between 1 and 4 has been assigned. Number 1 is designated as "favorable and low risk." Number 2 is "favorable and moderate risk," and number 3 is "less favorable and high risk." Number 4 is designated as "least favorable and highest risk." The sum of the risk numbers for each category for each scenario, results in an overall "composite project risk" score.

[redacted]

[redacted]

[redacted]

[redacted]

7 REMAINING UNCERTAINTIES

Recent and ongoing events have increased uncertainty around the future of Jim Bridger plant's fuel plans in a way that make definitive Jim Bridger long-term coal supply decisions or commitments high risk at this time. The following is a short summary of some of the major uncertainties that impact the 2023 Fuel Plan and an explanation of how the plan may change depending on the resolution of the uncertainties.

7.1 JIM BRIDGER GAS CONVERSIONS

Jim Bridger Units 1 and 2 are scheduled to be converted to natural gas in 2024 as required by a Regional Haze Consent Decree with the State of Wyoming. Based on the Company's 2023 IRP, Units 3 and 4 are scheduled to be converted to natural gas in 2030. The 2023 IRP analyzed a scenario where Jim Bridger Units 3 and 4 were not converted to natural gas, which resulted in significantly higher costs to PacifiCorp customers.[7] The natural gas conversion of Jim Bridger Units 1 and 2 is an enforceable environmental compliance requirement (Regional Haze requirements under the Clean Air Act (CAA)) under a consent decree entered into by the state of Wyoming and the Company[8] and an administrative consent order with EPA. The state of Wyoming issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 in December 2022, as well as submitted a state-approved revised regional haze state implementation plan to EPA requiring the natural gas conversion. EPA is reviewing the submission and is expected to conduct a separate federal public comment process on the plan in summer of 2023. PacifiCorp submitted a notice of compliance and request for termination of the EPA order in March of 2023, which is currently under EPA review. While some of these processes have not yet been finalized, and uncertainty remains, the gas conversion process is underway and any alternative compliance scenarios will be based on Units 1 and 2 converting to gas. The conversion of Units 3 and 4 is further out in time and thus subject to more uncertainty. Due to these uncertainties, [redacted]

7.2 PACIFICORP'S COMMITMENT AND REQUIREMENT TO EVALUATE CCUS AT JIM BRIDGER

Pursuant to Wyoming Statute §§ 37-18-101 and -102 and the Wyoming Public Service Commission Administrative Rules, PacifiCorp is required to analyze the suitability of CCUS at coal fired electric generation facilities, owned in whole or in part with another utility or utilities subject to the provisions of Wyo. Stat. § 37-18-102(a). The Company has determined that Jim Bridger Units 3 and 4 are potentially suitable candidates for CCUS. Additionally, the consent decree entered into by the state of Wyoming and the Company required the Company to issue request(s) for proposals (RFP) for the installation of CCUS at Jim Bridger Units 3 and 4 no later than January 1, 2023. PacifiCorp released the CCUS RFP to qualified bidders in November of 2022 for the Jim Bridger facility. [redacted]

CCUS installation at Jim Bridger Units 3 and/or 4 has the potential to significantly impact coal burn and dispatch. The generation forecast and coal requirement at the Jim Bridger plant will likely increase if PacifiCorp elects to, or is required to, install CCUS at Bridger Units 3 and/or 4. Proceeding with the Preferred Scenario in the near-term would not preclude the future installation of CCUS at the Jim Bridger plant while PacifiCorp continues to evaluate options and work to comply with Wyoming's CCUS regulations. Fueling strategies for CCUS scenarios would focus on availability and reliability of coal supply.

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[7] PacifiCorp's 2023 IRP, Chapter 9 – Modeling and Portfolio Selection Results, pages 266-267.
[8] Wyoming Consent Decree, Docket No. 2022-CV-200-333 (February 14, 2022).

7.3 PROPOSED EPA RULES

Ozone Transport Rule

The EPA proposed a federal implementation plan for 26 states, including Wyoming, in April of 2022, to eliminate significant contributions to nonattainment of the 2015 ozone National Ambient Air Quality Standard (NAAQS) in neighboring states, known as the Ozone Transport Rule, "good neighbor rule," or "interstate transport" provision of the CAA.[9] However, on January 31, 2023, EPA delayed final action on Wyoming's ozone interstate transport state implementation plan to December of 2023. Wyoming cannot be included in the federal plan until EPA disapproves the state plan. EPA finalized its federal ozone plan on March 15, 2023, but deferred action on Wyoming, meaning the state is currently not subject to the federal plan but could be once EPA finalizes its determination on the state plan. EPA's deferral of Wyoming is currently under litigation. EPA's federal plan is focused on reducing NOx, a precursor to ozone formation, and requires fossil-fuel-fired power plants to participate in an allowance-based ozone season trading program beginning in 2023. The federal rule includes SCR-like NOx budgets for each generating unit and will impact the Company and its operations. The final rule has been released by EPA but has not yet been published in the Federal Register, meaning compliance timelines are not yet established.

Jim Bridger Units 3 and 4 are currently equipped with SCR. Given the impacts of the federal plan on PacifiCorp's Utah coal plants, and depending on EPA's determination on Wyoming's state plan, these units may take on a more critical role in the compliance and reliability strategy for PacifiCorp's fleet and may operate at higher levels than previously forecasted during the ozone season (May – September). Proceeding with the Preferred Scenario, as explained above when discussing the possibility of CCUS at the Jim Bridger plant, keeps all the fueling alternatives on the table as PacifiCorp determines the most effective course of action for compliance with the rule and preserving reliability. Litigation of Utah and other state plan disapprovals is currently underway, and the final rule is also expected to be heavily litigated.

EPA's deferred action on Wyoming's state plan creates a great deal of uncertainty about how the Ozone Transport Rule will impact PacifiCorp's coal fleet. While this is pending, the Preferred Scenario is the most economical in the interim and will provide PacifiCorp time to better understand this potential regulation and its impacts on the generation fleet.

Greenhouse Gas Rule

EPA issued proposed regulations under section 111 of the CAA on May 23, 2023, to address greenhouse gas emissions from fossil-fuel fired electric generating units (the "Greenhouse Gas Rule"). The standards proposed in the rule would regulate new gas-fired combustion turbines and set standards for states to regulate existing coal plants, converted natural gas plants and certain large and frequently used existing gas turbine plants. The standards vary significantly based on facility-specific factors – including whether the unit is new or existing, whether it is fueled by coal or natural gas, how frequently it operates, and whether it is scheduled to retire in the coming years. Coal units operating beyond 2032 face increasingly stringent emission limits, and those operating beyond 2040 must comply with emission limits consistent with carbon capture and sequestration starting in 2030. PacifiCorp is evaluating the specific impacts of the proposal and how they impact the Bridger Units and the fueling plan. The impacts from the Greenhouse Gas Rule create some uncertainty due to changing future requirements for coal and gas units and because these requirements could be adjusted when the rule is finalized. The Preferred Scenario allows PacifiCorp

[9] *See* 42 U.S.C. 7410(a)(2)(D)(i)(I); 87 Fed. Reg. 20036 (April 6, 2022).

to maintain options to address the impacts and system-wide adjustments that may result from the proposed rule.

7.4 IDAHO POWER COMPANY'S PLANNED EXIT DATES

PacifiCorp's 2023 IRP Preferred Portfolio plans for Jim Bridger plant Units 1 and 2 to cease consuming coal on December 31, 2023, and convert to natural gas consumption. PacifiCorp's IRP also anticipates that Units 3 and 4 will cease consuming coal on December 31, 2029, and convert to natural gas. The IRP also provides December 31, 2037, as the closure date for all units. PacifiCorp and Idaho Power Company (Idaho Power) are aligned in the decision to consume coal in Units 1 and 2 through 2023, since Idaho Power's 2021 IRP calls for the conversion of two units to natural gas consumption in 2024. However, PacifiCorp and Idaho Power currently differ on the operation of Jim Bridger plant Units 3 and 4. Idaho Power's 2021 IRP provides December 31, 2025, as the closure date for a third Jim Bridger plant unit and December 31, 2028, as the closure date for a fourth Jim Bridger plant unit. Currently, these differences make modeling the Jim Bridger plant's future fueling needs difficult. Idaho Power is preparing an updated IRP which is scheduled to be released later in 2023. For purposes of the 2023 Fuel Plan, PacifiCorp has assumed the information in Idaho Power's 2021 IRP will remain the same. Ultimately, as co-owners of Jim Bridger plant and Bridger mine, PacifiCorp and Idaho Power will need to align their plans to best accommodate the unique needs of their respective customers. The solutions will impact each owner's access to and usage of the Jim Bridger plant and Bridger mine in the future.

8 CONCLUSION

In this 2023 Fuel Plan, PacifiCorp has identified a long-term fueling plan for the Jim Bridger plant that aligns with the Company's 2023 IRP, responds to changing fuel requirements, and allows flexibility to deal with uncertainty. This plan is PacifiCorp management's current strategy and lays out the various considerations and options available to PacifiCorp based on the best information available at this time. Alternative mine plans have been developed, evaluated, and reviewed for the Bridger mine which provided information and direction in determining the optimal volume at the Bridger mine.

After considering factors influencing this long-term fueling strategy and information available to the Company at this time, six different fueling options have been developed and evaluated. Based upon the results of the detailed PVRR analysis, which was further enhanced by utilizing a risk profile, the Preferred Scenario (Scenarios 5 and 6) provides the least-cost, risk-adjusted option and informs PacifiCorp's 2023 Jim Bridger plant fueling strategy. The Preferred Scenario assumes BCC operates two draglines. This plan would allow PacifiCorp [redacted]

[redacted]

[redacted]

Although the Preferred Scenario is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, energy market volatility and changing environmental legislation continues to create uncertainty around the future of Jim Bridger. PacifiCorp will continue to evaluate the best fueling options for the Jim Bridger plant as conditions change and as decision points for various supply options approach. PacifiCorp will update the long-term fuel supply plan after the 2025 IRP is finalized.

APPENDIX 1 – SCENARIO 1 – [redacted]

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 2 – SCENARIO 2 – [redacted]

[redacted]

APPENDIX 3 – SCENARIO 3 – [redacted]

[redacted]

APPENDIX 4 – SCENARIO 4 – [redacted]

[redacted]

APPENDIX 5 – SCENARIO 5 – [redacted]

[redacted]

APPENDIX 6 – SCENARIO 6 – [redacted]

[redacted]

APPENDIX 7 – JIM BRIDGER PLANT CONSUMED FUEL SUMMARY

[redacted]

APPENDIX 7 – JIM BRIDGER PLANT CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

APPENDIX 8 – SCENARIO 1 – JIM BRIDGER PLANT

[redacted]

APPENDIX 8 – SCENARIO 1 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 9 – SCENARIO 2 – JIM BRIDGER PLANT

[redacted]

APPENDIX 9 – SCENARIO 2 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 10 – SCENARIO 3 – JIM BRIDGER PLANT

[redacted]

APPENDIX 10 – SCENARIO 3 – JIM BRIDGER PLANT (CONT'D)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 11 – SCENARIO 4 – JIM BRIDGER PLANT

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 11 – SCENARIO 4 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 12 – SCENARIO 5 – JIM BRIDGER PLANT

[redacted]

APPENDIX 12 – SCENARIO 5 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 13 – SCENARIO 6 – JIM BRIDGER PLANT

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 13 – SCENARIO 6 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Jim Bridger Long Term Fuel Plan** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 31st day of May, 2023.

Santiago Gutierrez
Coordinator, Regulatory Operations

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Jim Bridger Long Term Fuel Plan** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 420

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Dated this 31st day of May, 2023.

Santiago Gutierrez
Coordinator, Regulatory Operations

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2024 Transition Adjustment Mechanism	Docket UE 420

CERTIFICATE OF SERVICE

I hereby certify that on this 23rd day of June, 2023, I have served true and correct copies of the confidential and highly confidential versions of the **Opening Testimony and Exhibits of Ed Burgess and Maria Roumpani on Behalf of Sierra Club** upon all eligible party representatives electronically via encrypted password protected .zip folders in compliance with OAR 860-001-0180.

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Dated this 23rd day of June, 2023 at Oakland, CA.

/s/ Leah Bahramipour

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