May 25, 2022

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
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puc.filingcenter@puc.oregon.gov

Re: In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism (Docket No. UE 400)

Enclosed please find the Opening Testimony and Exhibits of Ed Burgess (Sierra Club/100-120) on Behalf of Sierra Club in the above-captioned docket. The highly confidential and confidential versions of this filing will be provided to eligible parties pursuant to Protective Orders Nos. 16-128 and 22-063 via encrypted password protected .zip folders.

If you have any questions or require any additional information, please do not hesitate to contact me.

Respectfully submitted,

Ana Boyd
Research Analyst
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5649
ana.boyd@sierraclub.org

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2023 Transition Adjustment Mechanism	Docket UE 400

CERTIFICATE OF SERVICE

I hereby certify that on this 25th day of May, 2022, I have served true and correct copies of the confidential and highly confidential versions of the **Opening Testimony and Exhibits of Ed Burgess on Behalf of Sierra Club** upon all eligible party representatives electronically via encrypted password protected .zip folders in compliance with OAR 860-001-0180.

PACIFICORP
Ajay Kumar (C)(HC)
825 NE Multnomah St. Ste. 800
Portland, OR 97232
ajay.kumar@pacificorp.com
oregondockets@pacificorp.com

STAFF
Stephanie S Andrus (C) (HC)
PUC Staff--Department of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
stephanie.andrus@doj.state.or.us

Moya Enright (C) (HC)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308
moya.enright@puc.oregon.gov

AWEC
Brent Coleman (C) (HC)
Tyler C Pepple (C) (HC)
Jesse O Gorsuch (C) (HC)
Davison Van Cleve, PC
1750 SW Harbor Way Ste. 450
Portland, OR 97201
blc@dvclaw.com
tcp@dvclaw.com
jog@dvclaw.com

CUB
Jennifer Hill-Hart (C) (HC)
Bob Jenks (C) (HC)
610 SW Broadway, Ste. 400
Portland, OR 97205
jennifer@oregoncub.org
bob@oregoncub.org
dockets@oregoncub.org

NEWSUN ENERGY LLC
Brittany Andrus
3317 NE 31st Avenue
Portland, OR 97212
andruspdx@gmail.com

Max Yoklic
NewSun Energy
2033 E. Speedway Blvd, Suite 200
Tucson, AZ 85719
myoklic@newsunenergy.net

Jacob (Jake) Stephens
NewSun Energy
3500 S. Dupont Hwy
Dover, DE 19901
jstephens@newsunenergy.net

KWUA & OFBF
Paul S. Simmons (C)
Somach Simmons & Dunn, PC
500 Capitol Mall, STE 1000
Sacramento, CA 95814
psimmons@somachlaw.com
assist@kwua.org

Mary Anne Cooper (C) (HC)
Oregon Farm Bureau Federation
1320 Capitol St. NE Ste. 200
Salem, OR 97301
maryanne@oregonfb.org

CALPINE SOLUTIONS
Gregory M. Adams (C)
Richardson Adams, PLLC
515 N 27th St.
Boise, ID 83702
greg@richardsonadams.com

Greg Bass
Calpine Energy Solutions, LLC
401 West A St., Ste. 500
San Diego, CA 92101
greg.bass@calpinesolutions.com

Kevin Higgins (C)
Energy Strategies
215 State St. Ste, 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

NIPPC
Carl Fink (C)
Blue Planet Energy Law LLC
628 SW Chestnut St, Ste 200
Portland, OR 97219
cmfink@blueplanetlaw.com

Spencer Gray
NIPPC
P.O. Box 504
Mercer Island, Washington 98040
sgray@nippc.org

VITESSE LLC
Irion A. Sanger (C)
Sanger Law PC
1041 SE 58th Place
Portland, OR 97215
irion@sanger-law.com

Dennis Bartlett (C)
Jacob McDermott (C)
Meta Platforms, Inc.
dbart@fb.com
jacobmcdermott@fb.com

Dated this 25th day of May, 2022 at Oakland, CA.

/s/ Ana Boyd

Ana Boyd
Research Analyst
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5649
ana.boyd@sierraclub.org

Docket No. UE 400
Exhibit SC/100
Witness: Ed Burgess

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2023 Transition Adjustment Mechanism	Docket UE 400

Opening Testimony of Ed Burgess

On Behalf of
Sierra Club

Redacted Version

May 25, 2022

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I. Summary of Findings and Recommendations

Q. Please provide a summary of your testimony.

A. My testimony examines the fuel expenditures PacifiCorp proposes to recover through its 2023 Transition Adjustment Mechanism ("TAM"). I identify several problems in the Company's coal fuel expenditures that are leading to higher ratepayer costs than necessary. I also provide several recommendations that help to correct these issues.

Q. Please provide a summary of your findings.

A. My findings can be summarized as follows:

1. PacifiCorp's 2022 Jim Bridger Long-Term Fuel Supply Plan ("LTFSP") has numerous flaws that severely limit its ability to identify a prudent course of action for the Jim Bridger plant's 2023 fuel supplies. These flaws include: 1) the use of a dispatch model that does not accommodate multiple fuel price inputs within the same scenario; 2) the lack of any scenario without Black Butte coal; 3) the lack of sufficient justification for the modeled Bridger Coal Company ("BBC" or "Bridger mine") production levels, 4) inconsistency with the 2021 IRP analysis and 2023 TAM AURORA analysis; and 5) the inclusion of minimum take volumes for both BCC and Black Butte in 2023 when there are none for either.

2. PacifiCorp is seeking rate approval of estimated 2023 fuel costs for the Black Butte coal supply without providing any analysis or justification for the price and quantity of the estimated coal fuel costs.

3. PacifiCorp is seeking rate approval for its 2023 BCC operating costs without providing any justification for its proposed mine plan and associated production

quantity. In fact, the 2023 mine plan PacifiCorp has proposed is inconsistent with its own LTFSP for Jim Bridger.

4. Recent dispatch model runs show that significantly reducing Jim Bridger output (i.e., on the order of [redacted] percent) in 2023 could be beneficial to ratepayers

5. The Jim Bridger plant's annual CO_2 emissions are equivalent to approximately 61 percent of Oregon's entire power sector GHG emissions.

6. In PacifiCorp's new Aurora modeling software, the Company modeled the Jim Bridger plant with a "minimum take" requirement of approximately [redacted] tons ([redacted] MMBtu) in 2023 even though no such requirement exists. Even if the BCC base quantity were considered to constitute a "minimum take," it would be substantially lower (i.e., on the order of [redacted] tons).

7. PacifiCorp's analysis of the Huntington coal supply agreement ("CSA") did not include [redacted].

Q. Please provide a summary of your recommendations.

A. My recommendations are:

1. The Commission should require PacifiCorp to update its Jim Bridger LTFSP in each future TAM proceeding going forward. Analysis supporting these updates should include the following features:

   a. Must be conducted with a model that can handle multiple fuel price tiers (e.g., PLEXOS, Aurora, or similar software), like the Company's approach to evaluating the Naughton CSA.

   b. Must include a scenario without any coal from future CSAs (e.g., Black Butte).

c. Must include a scenario with no minimum take assumptions from BCC.

d. Must evaluate a scenario where no new coal is sourced after [redacted], and Jim Bridger relies on stockpiled coal through 2037.

2. The Commission should exclude the estimated Black Butte costs from TAM rates until the Commission has had an opportunity to review an analysis from PacifiCorp demonstrating the prudency of a new Black Butte CSA. Excluding these costs would reduce the total 2023 Net Power Cost ("NPC") by approximately $[redacted].

3. The Commission should exclude the estimated BCC fuel costs from the 2023 TAM rates until PacifiCorp is able to provide sufficient justification for the production volume selected as part of its 2023 BCC base plan. Excluding these costs would reduce the total NPC by approximately $[redacted]. Alternatively, the BCC fuel costs included in 2023 TAM rates should correspond to the quantity included in Scenario 5 of the LTFSP (PacifiCorp's preferred option).

4. In adopting the above two recommendations, I recommend the Commission reduce the 2023 TAM rates by a corresponding amount. This would equate to a reduction in the Oregon-allocated portion of the NPC of approximately $[redacted], or about [redacted] percent. In the alternative, should the Commission permit recovery of BCC fuel costs aligned with Scenario 5 of the LTFSP, Oregon-allocation NPC should be reduced by $[redacted].

5. In each TAM going forward, PacifiCorp should be required to present a range of BCC mine plan options with different production volumes and a detailed analysis

supporting the plan it ultimately selects. This plan should be consistent with an annual LTFSP update.

6. In all future TAM proceedings, the Commission should require PacifiCorp to model the NPC using a minimum take volume for Jim Bridger that reflects the lowest feasible base quantity production for BCC. For the 2023 TAM, this value should have been between 0 to [redacted] MMBtu, rather than the [redacted] MMBtu assumed.

7. Going forward, PacifiCorp should provide more transparency, in advance, regarding the scenarios it intends to use to evaluate new CSAs and mine plans. At a minimum, PacifiCorp should provide a list of the key assumptions that differ between the scenarios.

8. If the Naughton CSA [redacted], the Commission should evaluate whether any increased cost could have reasonably been avoided through alternatives.

9. The Commission should require PacifiCorp to supplement its Huntington termination evaluation with [redacted].

II. <u>Introduction</u>

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

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please summarize your professional and educational background.

A. I am a leader 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 resume is attached as Exhibit Sierra Club/101.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of my 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) analyze PacifiCorp's treatment of coal fuel costs from the Bridger Coal Company. I also provide recommendations on how to improve future TAM proceedings.

Q. Have you ever testified before this Commission?

A. Yes. I testified in UE-375 and UE-390, which were PacifiCorp's 2021 and 2022 TAM proceedings, respectively.

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

A. 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. EPA'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 California Public Utilities Commission on PacifiCorp's proposed 2020 and 2021 Energy Costs Adjustment Clause ("ECAC") proceedings, which is the California equivalent of the TAM.

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

A. Yes. I have testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General's Office ("AGO") at the evidentiary hearings for D.P.U. 18-150 and D.P.U. 17-140. I have also supported the AGO as a technical consultant in other cases including D.P.U. 17-05, D.P.U. 17-13, D.P.U. 15-155, and

D.P.U. 17-146. I have also testified before the South Carolina Public Service Commission on behalf of the South Carolina Solar Business Alliance in evidentiary hearings for 2019-186-E, 2019-185-E, and 2019-184-E. I provided written testimony to the Indiana Utility Regulatory Commission on behalf of the Citizens Action Coalition and Earthjustice on coal fuel costs in two proceedings related to Duke Energy's Fuel Adjustment Clause (IURC Cause No. 38707 FAC 123 S1 and FAC 125). I also recently provided testimony to the Nevada PUC on NV Energy's Integrated Resource Plan in (Docket No 20-07023). Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at Public 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.

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

- An overview of the key features of PacifiCorp's proposed 2023 TAM;
- A detailed critique of PacifiCorp's updated Long Term Fuel Supply Plan for the Jim Bridger Plant;
- A detailed critique of forecasted 2023 fuel costs for Jim Bridger that PacifiCorp proposes to include in the 2023 TAM (including cost related to both Black Butte and the Bridger mine);

- An explanation of recent modeling runs showing that significantly reducing Jim Bridger output would be beneficial to ratepayers
- An explanation of how PacifiCorp used inappropriate minimum take assumptions at Jim Bridger in Aurora
- Recommended adjustments to PacifiCorp's proposed 2023 TAM rates
- A high-level assessment of PacifiCorp's newly executed Naughton coal supply agreement
- A high-level assessment of PacifiCorp's evaluation of its existing Huntington coal supply agreements.

III. The Transition Adjustment Mechanisms and PacifiCorp's 2023 Application

A. Overview of the 2023 TAM

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 $0.02-0.025/kWh, or roughly 20-25 percent of standard residential energy rates.[1] 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 2023 TAM.

A. On March 1, 2022, PacifiCorp submitted an application to this Commission requesting authorization to update certain components of its TAM for 2023. The application also discusses the transition to the Aurora model and their proposed modeling changes. As required by the 2022 TAM Order, PacifiCorp filed an updated Long-Term Fuel Supply Plan for the Jim Bridger coal plant on April 15, 2022 and an analysis of the Huntington CSA on April 28, 2022.

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 purchase power expenses and wheeling expenses, less wholesale sales revenue.

[1] Assuming $0.10/kWh for baseline PacifiCorp's residential energy charges.

Q. Have you reviewed PacifiCorp's testimony and supporting workpapers in this proceeding regarding the calculation of the 2023 TAM?

A. Yes. I reviewed the testimony and supporting workpapers. The primary component of the 2023 TAM is PacifiCorp's forecasted NPC for the year 2023, a portion of which is allocated to Oregon.

Q. What is the total-company NPC in the TAM for calendar year 2023?

A. The forecasted normalized total-company NPC for calendar year 2023 is $1.684 billion.[2] This is approximately $314 million higher than the 2022 TAM's forecasted NPC, which was approximately $1.369 billion. Approximately 25 percent of the forecasted NPC, or $429 million, is allocated to Oregon.[3]

Q. What adjustments are made to NPC for the purpose of setting the 2022 TAM power supply rates?

A. The largest adjustment is the subtraction of the Production Tax Credit, which totals $269 million for 2023, or $70 million for Oregon. Additional Oregon Situs NPC adjustments result in a $0.4 million reduction. Thus, the Oregon-allocated revenue requirement targeted for rate recovery through the TAM is approximately $359 million.[4]

Q. Can you summarize the underlying components of the NPC in TAM 2022?

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

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[2] PAC/101 at Wilding/1.
[3] PAC/101 at Wilding/1.
[4] *Id.*

Table 1. 2023 NPC Components

Category	**Total Company (million)**	**Oregon allocated (million)**
Sales for resale	$ 356	$ 93
Purchased power	$ 950	$ 247
Wheeling expense	$ 161	$ 42
Fuel expense	$ 928	$ 233
Coal Fuel Burn expenses	*$ 600*	*$ 150*
Gas/Other Fuel Burn expenses	*$ 328*	*$ 82*
Net power cost (per Aurora)	$ 1,684	$ 429
Oregon situs NPC adjustments	$ (0.4)	$ (0.4)
Total NPC	$ 1,683	$ 429

As the table above shows $600 million of fuel costs are for coal fuel expenses. Thus, nearly 36 percent of the NPC is comprised of costs for burning coal.

B. Cost of Coal Fuel Included in the 2023 TAM

Q. Can you provide a breakdown of the coal fuel burn expenses that are included in the 2023 NPC Projections?

A. Yes. The anticipated 2023 coal fuel burn expenses can be broken down by plant as follows:

Confidential Table 2. Unit Average Cost Based on 2023 Projected NPC and Generation

Plant	2023 Projected Coal Burn Expenses ($)[5]	2023 Projected Generation (MWh)[6]	Average Cost ($/MWh)[7]
Cholla	$ -	[redacted]	[redacted]
Colstrip	$ 18,388,036	[redacted]	[redacted]
Craig	$ 14,393,703	[redacted]	[redacted]
Dave Johnston	$ 63,751,340	[redacted]	[redacted]
Hayden	$ 10,169,525	[redacted]	[redacted]
Hunter	$ 126,226,934	[redacted]	[redacted]
Huntington	$ 110,658,947	[redacted]	[redacted]
Jim Bridger	$ 196,125,182	[redacted]	[redacted]
Naughton	$ 27,974,534	[redacted]	[redacted]
Wyodak	$ 32,280,937	[redacted]	[redacted]
Total	$ 599,969,137	[redacted]	[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 2023. 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 Naughton and Jim Bridger plants have projected coal fuel burn expenses of $[redacted]/MWh and $[redacted]/MWh, respectively. These figures are not necessarily surprising, as Sierra Club has pointed out that Naughton and Jim Bridger have been PacifiCorp's highest cost coal plants in the last two TAM proceedings.[8]

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[5] PAC/102 at Wilding/5.

[6] Confidential workpaper accompanying PacifiCorp's 2023 TAM Application "ORTAM23 NPC CONF" at "NPC" tab. [hereinafter "ORTAM23 NPC CONF"].

[7] *Id.*

[8] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Opening Testimony of Ed Burgess (Sierra Club/100) at Burgess/16:5-11 (May 15, 2020), *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue375htb174343.pdf (excerpt attached as Exhibit Sierra Club/102); *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Opening Testimony of Ed Burgess (Sierra Club/100) at Burgess/15:2-6 (June 9, 2021), *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue390htb164812.pdf [hereinafter "2022 TAM Sierra Club/100"] (excerpt attached as Exhibit Sierra Club/103).

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 the TAM, such as operations and maintenance costs. Additionally, PacifiCorp owns the 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 2023 TAM differ from the 2022 TAM projection?

A. PacifiCorp's projected coal fuel expense is $57 million higher, or over 10 percent more, than the 2022 TAM forecast.[9] Coal costs are projected to be higher by [redacted] percent on a $/MWh basis.[10] Despite this increase PacifiCorp projects higher coal generation compared to the 2022 TAM.

Q. Has PacifiCorp executed any new coal supply agreements since the 2022 TAM proceeding that have not yet been reviewed by the Commission?

A. Yes. PacifiCorp executed a new coal supply agreement for the Naughton plant (with the Kemmerer mine) in December 2021 that extends into the 2023 TAM forecast year and beyond. 2022 TAM costs were based on estimates of the new Naughton CSA at the time. PacifiCorp had also anticipated new fuel sources for the Jim Bridger plant, including a 2023 Operating Plan for the Bridger mine, and a new CSA with the Black Butte mine.

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[9] PAC/101 at Wilding/1; *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Exhibit PAC/101 to the Direct Testimony of David G. Webb at Webb/1 (Apr. 2021), *available at* https://edocs.puc.state.or.us/efdocs/UAA/ue390uaa15412.pdf.
[10] Sierra Club/103, 2022 TAM Sierra Club/100 at Burgess/13 (Confidential Table 2) (comparing the cost of projected generation on a $/MWh basis in the 2022 TAM to the cost in the instant proceeding).

Additionally, as noted above, PacifiCorp provided a new Long-Term Fuel Supply Plan for the Jim Bridger Plant (updated April 2022), which includes an analysis of both these fuel sources.

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

A. Yes. I will explain my concerns about each in the sections below.

Q. What is the significance of these fuel sources from a GHG emissions perspective?

A. The Jim Bridger plant is one of the largest remaining coal-fired power plants in the western United States. In 2019, the Jim Bridger plant created approximately 11.5 MMT of CO_2 emissions.[11] To put this in perspective, this equates to about 61 percent of Oregon's entire electricity sector greenhouse gas emissions for the same year.[12]

IV. Review of 2022 Jim Bridger Long Term Fuel Supply Plan

Q. Have you reviewed PacifiCorp's Highly Confidential Long-Term Fuel Supply Plan ("LTFSP") for the Jim Bridger Plant which was provided on April 15, 2022?

A. Yes.

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

A. Yes. The Plan provides an analysis of five potential fueling scenarios for Jim Bridger from 2022 through its currently planned retirement date of 2037, as well as an average cost dispatch analysis. Under Scenario 1, the plant is [redacted]

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[11] Based on emission data sourced from EPA's Continuous Emissions Monitoring System ("CEMS") and compiled by S&P Global Market Intelligence.

[12] Based on Oregon DEQ Greenhouse Gas Inventory Data. *Oregon Greenhouse Gas Sector-Based Inventory Data*, State of Oregon Department of Environmental Quality, *available at* https://www.oregon.gov/deq/aq/programs/Pages/GHG-Inventory.aspx (last accessed May 24, 2022).

[redacted] under Scenario 2, the plant is [redacted], and under Scenarios 3-5 the plant is [redacted].[13] PacifiCorp's analysis shows that [redacted].[14] PacifiCorp also studies a sixth scenario, which was [redacted] used the "average cost" to dispatch the Jim Bridger plant instead of an incremental cost.[15]

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

A. Yes, I have several concerns. Chief among these is the fact that PacifiCorp used the GRID model to conduct its analysis for this plan,[16] despite the fact that the GRID model has significant deficiencies and has already been phased out of PacifiCorp's other planning activities in favor of superior tools such as Aurora, which is now used for the TAM, and PLEXOS, which is used for long-term planning in PacifiCorp's IRP and the most recent Naughton coal supply agreement. Additionally, even though the LTFSP is a long-term analysis over a 15-year period, it is not consistent with PacifiCorp's 2021 IRP, which was acknowledged by the Commission just a few weeks prior.[17] In fact, it constitutes an entirely different generation forecast and dispatch model that has no clear relation to the 2021 IRP.

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[13] PacifiCorp Highly Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant at 13-15 (Apr. 15, 2022) [hereinafter "Highly Confidential Bridger LTFSP"]. A redacted version of the LTFSP was provided in the PacifiCorp Response to Sierra Club Data Request 4.2 and is attached as Exhibit Sierra Club/104.
[14] *Id.* at 17.
[15] *Id.* at 20.
[16] Redacted Bridger LTFSP at 6.
[17] The Commission orally acknowledged PacifiCorp's 2021 IRP with modifications and exceptions on March 29, 2022 at a Special Public Meeting. On May 23, 2022, the Commission's final order doing the same was entered. *See In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket. No. LC 77, Order No. 22-178 (May 23, 2022), *available at* https://apps.puc.state.or.us/orders/2022ords/22-178.pdf.

Q. Did PacifiCorp use GRID to evaluate other coal fuel supplies in this case?

A. No. For example, and as noted above, PacifiCorp used PLEXOS to evaluate the new Naughton CSA. This Naughton evaluation also included inputs largely similar to those included in PacifiCorp's IRP. This demonstrates that PacifiCorp had the capability to evaluate Jim Bridger's fuel supply using a tool other than GRID but chose not to.

Q. Are there specific features of GRID that are especially concerning in conducting the LTFSP analysis?

A. Yes. One of the main reasons PacifiCorp transitioned from GRID to Aurora for modeling NPC costs in the TAM is the fact that GRID can only accept one fuel price input for each generation unit when conducting dispatch simulations. As explained in the testimony of PacifiCorp witness Michael Wilding, the Aurora model no longer uses separate dispatch and costing tiers, and instead "can receive more than one incremental price for the purpose of forecasting dispatch of coal fueled resources."[18] This underscores the fact that GRID is particularly ill-suited for an analysis like the LTFSP whose primary purpose is to evaluate multiple possible combinations of fuel sources at Jim Bridger where each fuel source may have different price inputs and tiers within the same scenario. In contrast, both PLEXOS and Aurora are able to model multiple fuel price inputs, including CSAs with multiple price tiers and take-or-pay volumes, within the same scenario. PacifiCorp has alluded to the fact that it used multiple GRID dispatch prices for each of the six scenarios,[19] but this is misleading since each scenario still only considers one price, and

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[18] PAC/100 at Wilding/16:15-16.
[19] *See* Sierra Club/104, Redacted Bridger LTFSP at 6.

therefore does not constitute a comprehensive analysis in the same way that using PLEXOS or Aurora would.

Q. Did Sierra Club ask PacifiCorp why it did not use Aurora or PLEXOS for the LTFSP?

A. Yes. In response to Sierra Club Data Request 4.5, PacifiCorp stated that Aurora "is not yet configured and maintained to perform longer term model runs beyond a one-year period."[20] In response to Sierra Club Data Request 4.6, PacifiCorp provided two reasons for why PLEXOS was not used. First, according to PacifiCorp's response, PLEXOS "receives less frequent input and configuration updates than [GRID]."[21] GRID, on the other hand, received monthly updates, putting the GRID model "in a better position for meeting the Jim Bridger Long-Term Fuel Supply Plan deadline."[22] Second, PacifiCorp also noted that GRID "regularly compares coal generation forecast results to actual results and makes forecast adjustments as are necessary, whereas the PLEXOS model results performed by the Company's IRP group is focused on comparing generation results from one scenario to another, rather than comparing generation forecasts to actual results."[23]

Q. Do these explanations satisfy your concerns that PacifiCorp chose to use GRID to update its LTFSP for Jim Bridger?

A. No, not as it pertains to PLEXOS. While I understand that Aurora may not have been ready to complete the required analysis, PacifiCorp's response regarding why the

[20] PacifiCorp Response to Sierra Club Data Request 4.5 The UE 400 public data responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/105.
[21] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 4.6.
[22] *Id.*
[23] *Id.*

Company did not use PLEXOS, despite the ability to input multiple fuel prices in that model, is not compelling. First, it is not clear why PLEXOS could not have received the necessary "input and configuration updates" prior to completing the LTFSP. Even if these updates could not have been completed in time, it is not clear that such updates were more important than the ability to accurately incorporate coal fuel price inputs, given that the purpose of the LTFSP was to evaluate different fueling options for Jim Bridger, which is necessarily dependent on the different price points for each individual fuel source. Second, it seems to me that the Commission intended for the LTFSP to "compar[e] generation results from one scenario to another," similar to an IRP analysis. In fact, this seems more in line with the Commission's request than PacifiCorp's presumption that the Commission wanted PacifiCorp to "compar[e] generation forecasts to actual results." Not only did comparative scenario analysis seem to be the Commission's intent, it is, in fact, what PacifiCorp presented in its LTFSP document. Just as in the IRP, PacifiCorp provided a present-value revenue requirement ("PVRR") analysis for each scenario in the LTFSP in order to compare the results. This seems highly aligned with how PLEXOS was used in the IRP, meaning that it would have been a similarly appropriate tool for the LTFSP. Moreover, PacifiCorp's analysis in the LTFSP was forward looking and did not focus on comparing its forecast to actual results.

Q. Did PacifiCorp's LTFSP analysis assume minimum take volumes for coal fuel from Black Butte and the Bridger mine in 2023?

A. Yes. My understanding is that PacifiCorp assumed that for both Black Butte and BCC coal, there would be a minimum volume.[24] For Black Butte, this was equal to [redacted] tons in all scenarios except for the average cost run, which was [redacted] tons. For BCC, this was equal to the base tonnages shown in Appendices 13-18, which are summarized in the table below.

Highly Confidential Table 3. LTFSP Assumed BCC Minimum Take Volumes

Scenario	BCC Base Tons (millions) 2023—PacifiCorp's Share
LTFSP Scenario 1 ([redacted])	[redacted]
LTFSP Scenario 2 ([redacted])	[redacted]
LTFSP Scenario 3 ([redacted])	[redacted]
LTFSP Scenario 4 ([redacted])	[redacted]
LTFSP Scenario 5 ([redacted])	[redacted]
LTFSP Scenario 6 ([redacted])	[redacted]

Q. Are these minimum take volumes at Black Butte and BCC concerning to you?

A. Yes. They are concerning to me because there was no minimum take quantity for either fuel source in 2023 or beyond at the time the analysis was conducted. Thus, PacifiCorp's analysis would inherently fail to consider whether a lower volume, or even no volume, is a more economic option. Put another way, by imposing minimum take requirements for both Black Butte and BCC, PacifiCorp ensured that the model would forecast a need for those fuel sources, even if lower cost, cleaner alternatives were more economic. As

[24] *See, e.g.*, Sierra Club/105, PacifiCorp Response to Sierra Club Data Requests 4.3(c), 4.8(a) (acknowledging that PacifiCorp did not include a no-minimum scenario for BCC in the Long-Term Fuel Supply Plan); Sierra Club/104, Redacted Bridger LTFSP at 9 (describing anticipated Black Butte CSA and noting that the anticipated contract "volumes and pricing [were] used in the 2022 Fuel Plan").

discussed below, this is not the approach that PacifiCorp has taken for any other coal plant when evaluating long term resource needs, either through its IRP[25] or in evaluating tonnage requirements for new CSAs.

Q. How does PacifiCorp generally ensure minimum take volumes are met in the GRID model?

A. Historically, when using GRID, PacifiCorp has used an "iterative process" where it makes manual adjustments to the dispatch price until the minimum volume is consumed.[26] Meanwhile, the NPC fuel cost is calculated using a higher average price. In some cases, this would lead to a higher level of coal dispatch than would otherwise be the case if the full cost of fuel (i.e., the average price) were used as the dispatch price.

Q. How does PacifiCorp typically model new coal supply agreements in GRID where there is no pre-existing minimum take volume?

A. PacifiCorp's standard practice when evaluating a new CSA is to use the full average cost as the dispatch price in GRID. This is the only way to determine if both the price and take-or-pay volume being contracted are prudent and in its' customers' best interests. After the contract is executed, PacifiCorp then uses the iterative approach of adjusting the dispatch price to ensure the take-or-pay volume is always met. For example, when PacifiCorp created generation forecasts to inform an appropriate minimum take requirement in its new Hunter and Dave Johnston contracts (presented in the 2022 TAM),

[25] *In the Matter of PacifiCorp's 2021 Integrated Resource Plan*, Utah Pub. Serv. Comm'n Docket No. 21-035-09, PacifiCorp Response to Western Resource Advocates Data Request 4.28 (attached as Exhibit Sierra Club/106) (stating that for all coal plants other than Jim Bridger, the Company did not assume that the coal plant would be subject to a new coal contract with minimum take requirements following the expiration of a current coal contract).

[26] *See e.g.*, *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Direct Testimony of David G. Webb (PAC/100) at Webb/30:13-16 (Apr. 2021), *available at* https://edocs.puc.state.or.us/efdocs/UAA/ue390uaa15412.pdf.

PacifiCorp used average costs in GRID.[27] This is also consistent for how PacifiCorp modeled the majority of its coal supplies in its 2021 IRP, where, except for Jim Bridger, once a current coal supply agreement expired, PacifiCorp modeled the plant using average costs.[28]

Q. Did PacifiCorp use the same approach for evaluating the Hunter and Dave Johnston CSAs as it did for evaluating Black Butte and BCC in the LTFSP?

A. No. PacifiCorp presumed ahead of time that these fuel supply volumes for Black Butte and BCC would be fixed, and did not model them using average costs. Instead, they used a lower dispatch price as if the presumed coal volumes were a foregone conclusion. In this sense, the fact that the LTFSP included dispatch levels that exceeded PacifiCorp's predetermined volumes amounts to a self-fulfilling prophecy.

Q. Do you suspect that this approach is skewing the dispatch of Jim Bridger higher than is economic?

A. Yes.

[27] *In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2021 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, Proceeding No. A.20-08-002, Direct Testimony of Ed Burgess on Behalf of Sierra Club (SC-01) at 24:15-25 (Cal.P.U.C. Mar. 18, 2021), *available at* https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2008002/3443/372113819.pdf.

[28] Sierra Club/106; *In the Matter of PacifiCorp's 2021 Integrated Resource Plan*, Utah Pub. Serv. Comm'n Docket No. 21-035-09, PacifiCorp Response to Western Resource Advocates Data Request 4.2 (attached as Exhibit Sierra Club/107).

Q. In Commission Decision No. 21-379, the Commission "encourage[d] PacifiCorp to look at . . . the consequences of fueling Jim Bridger solely from BCC or solely from Black Butte."[29] Do you believe PacifiCorp did so in the 2022 LTFSP?

A. No, I do not. PacifiCorp did not evaluate any scenarios without fuel from Black Butte.[30] This is concerning to me because, at the time of its application, PacifiCorp had no obligation to purchase fuel from the Black Butte mine for the majority of 2022 or at all in 2023 or beyond. When asked about this, PacifiCorp merely stated "[c]oal from the Black Butte mine is required in every scenario to fuel Jim Bridger plant generation as forecast by PacifiCorp's [GRID] model through 2022 and 2023."[31] While PacifiCorp may believe that Black Butte coal is required, it does not appear that the Company conducted any modeling that would support its hypothesis. Additionally, several of the scenarios include incremental coal fuel from Black Butte in 2023, beyond the [redacted]-ton base quantity, despite the fact that PacifiCorp's preliminary discussions with the coal supplier did not suggest substantial supplemental coal would be needed, and none was assumed in the 2023 TAM.[32]

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[29] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 14 (Nov. 1, 2021), *available at* https://apps.puc.state.or.us/orders/2021ords/21-379.pdf [hereinafter "Order No. 21-379"].
[30] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 4.7.
[31] *Id.*
[32] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 5.4(f).

Q. You mentioned that the 2022 LTFSP included an "average cost" GRID run. Has Sierra Club previously argued in cases where there is no existing contract (e.g., for Black Butte) that the total or "average cost" is the correct input when conducting model runs in GRID or other simulations models?

A. Yes, that is also consistent with PacifiCorp's recent practice for evaluating new coal supply agreements, which I mentioned above. I discuss further below, in Section VI(A), why average cost modeling is appropriate when no minimum take requirements are in effect.

Q. Do you think that Scenario 6, the "average cost" dispatch analysis, included in the LTFSP provides an accurate representation of Sierra Club's previous recommendations?

A. No. There are several features of Scenario 6 that have not been explained by PacifiCorp and lead me to question its usefulness. These features include:

1. The amount of generation forecasted at the Jim Bridger plant in 2022, (i.e., [redacted] GWh),[33] [redacted]. This is true despite the fact that [redacted]. For example, the Jim Bridger [redacted][35] Having [redacted];

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[33] Highly Bridger Confidential LTFSP at Apps. 13-18.
[34] Highly Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 4.1 "GEN Forecast_2022BP_v2_20220314_Scenario 3" at "Generation Budget" tab (attached as Exhibit Sierra Club/108).
[35] Highly Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 4.1 "GEN Forecast_2022BP_v2_20220314_Scenario 6", at "Generation" Tab (attached as Exhibit Sierra Club/109).

2. Scenario 6 seems to include a base volume of coal from Black Butte that is inconsistent with PacifiCorp's testimony. For example, Scenario 6 shows a delivered volume of [redacted] tons in 2023, instead of the anticipated [redacted] annual tons described by Mr. Owen.[36] The base quantity in Scenario 6 for 2022 and 2023 also [redacted];

3. In contrast to Scenarios 3-5, Scenario 6 projects [redacted].[37] This suggests that the model run using average costs is [redacted]. However, it is not clear how [redacted];

4. If the coal fuel from Black Butte in 2022 and 2023 were allowed by the model to be replaced entirely with energy from another source (either at Jim Bridger, or from another generator), then it is conceivable that the cost of Scenario 6 could be the least cost scenario.

Q. Do you have any other concerns with the 2022 LTFSP?

A. Yes. I have at least two. First, it is unclear how PacifiCorp developed the various production scenarios for the Bridger mine and whether these capture the full range of possible production options and needs. According to Appendices 15-18, the lowest assumed "base" BCC tonnage was [redacted],[38] for PacifiCorp's share. Assuming that

[36] *Compare* Highly Confidential at LTFSP App. 18 *with* PAC/200 at Owen/18:11.
[37] Highly Confidential Bridger LTFSP at Apps. 15-18.
[38] *Id.*

Idaho Power's share would necessitate 33.3 percent more base tonnage, this means that the lowest base tonnage considered was actually [redacted], significantly higher than what the LTFSP identifies as the low end of BCC production, [redacted] tons.[39] Even assuming that [redacted] tons is the absolute lowest viable production volume at BCC (and it may be lower, [redacted]), PacifiCorp's share would be approximately [redacted] tons. As discussed further below in the context of PacifiCorp's proposed 2023 coal prices for BCC, the LTFSP does not appear to have evaluated that level of production. Second, it is unclear whether all of the costs of the Bridger mine are included in PacifiCorp's LTFSP analysis, including mine costs that are recovered outside of the TAM.

Q. Based on these deficiencies how do you think the results of the LTFSP analysis should be interpreted?

A. I think the results of the LTFSP analysis should be treated with great skepticism. At a minimum, the plan does seem to indicate that a scenario [redacted]. However, I do not think the plan provides sufficient justification for any specific production level at the Bridger mine or a renewed contract with Black Butte, even on a short-term basis.

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[39] *Id.* at 7.

Q. How do the GRID model results in the LTFSP compare to the "No Minimum" PLEXOS run conducted in the Company's 2021 IRP, where the Company did not assume as a foregone conclusion that it would be subject to minimum take requirements at Jim Bridger's fuel supplies?

A. They are very different. The chart below illustrates the difference in generation forecasted at Jim Bridger in a 2021 IRP PLEXOS model run[40] and in the LTFSP GRID run for the Bridger mine [redacted].[41] Notably, the generation in 2023 is approximately [redacted] in the PLEXOS run than in the GRID runs. This is true when comparing to [redacted] scenarios since the GWh of generation at Jim Bridger in 2023 is [redacted].

Highly Confidential Figure 1. Jim Bridger Generation Under the 2021 IRP "No Minimum Scenario" and Scenarios in the 2022 Long Term Fuel Supply Plan

[redacted]

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[40] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.15 "Attach SC 2.15-1 CONF" [hereinafter "Attach SC 2.15-1 CONF"] (attached as Exhibit Sierra Club/110).
[41] Highly Confidential Bridger LTFSP at Apps. 15, 17.

Q. How is the "No Minimum" 2021 IRP model run relevant to this proceeding?

A. In the 2021 IRP proceeding, PacifiCorp conducted a PLEXOS model run without any take-or-pay minimum constraints assumed for Jim Bridger's fuel sources.[42] This is especially appropriate for assessing Jim Bridger fuel costs in the 2023 TAM (and beyond) since there would be no take-or-pay minimums in effect for either the Black Butte or BCC fuel sources. While Black Butte previously had a contractual minimum in the past, that is no longer true as of May 1, 2022 when the contract expires.

Q. What do you think explains the [redacted] percent discrepancy in generation between the LTFSP and the IRP's No Minimum Scenario in 2023?

A. One possible explanation is the fact that the LTFSP includes Black Butte in 2023 with a minimum take obligation of [redacted].[43] As mentioned, the IRP model runs suggest that a [redacted] in generation at Jim Bridger is economic when there are no contract minimums considered.[44] Notably this [redacted] is *virtually identical* to the amount of coal fuel delivered to Jim Bridger from Black Butte in 2023 under the LTFSP scenarios. In other words, if no minimum take obligation is assumed *a priori* it may be economic not to consume <u>*any*</u> coal from Black Butte, which would readily explain the [redacted]. This strongly suggests that the Black Butte contract should likely not be renewed for 2023, even on a short-term basis.

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[42] Sierra Club/110, Attach SC 2.15-1 CONF.
[43] Highly Confidential Bridger LTFSP at Apps. 13-17.
[44] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.8 "Attach SC 2.8-2 CONF" (attached as Exhibit Sierra Club/111).

Q. Do you think it is possible that it would be prudent to reduce generation at Jim Bridger even more than [redacted] percent in 2023?

A. Possibly. The No Minimum Scenario provided in the 2021 IRP proceeding was only provided days before final comments were due and there was no time for Sierra Club to conduct subsequent discovery. It is possible that PacifiCorp may have included certain minimum constraints on Bridger mine production in 2023 and 2024 given the additional discrepancy between generation in those years and subsequent years.

Q. Do you have concerns about the LTFSP for future TAM proceedings?

A. Yes. In comparison to the IRP, the LTFSP appears to overestimate the total coal deliveries from the Bridger mine (and other sources) that are needed to operate the Jim Bridger plant through 2037. For comparison, the [redacted]. In contrast, the IRP No Minimum Scenario model generation levels indicate that less than [redacted] tons are needed for the same period.[45] Notably, PacifiCorp expects about [redacted] tons of coal to be stockpiled at the end of 2023.[46] This means only about [redacted] of additional coal is needed for the remainder of the plant's useful life.

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[45] Author's calculation. Highly Confidential workpaper accompanying the Opening Testimony of Ed Burgess "LTFSP Comparison_HIGHLY CONF" [hereinafter "LTFSP Comparison_HIGHLY CONF (Burgess)"].

[46] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 3.13 "Attach SC 3.13 CONF" (attached as Exhibit Sierra Club/112). (notably, this references PacifiCorp's portion of stockpiled coal, meaning that the figure could be up to 33 percent higher to account for Idaho Power's portion).

Q. According to PacifiCorp's 2023 Bridger mine operating plan for this proceeding, how much coal is expected to be produced from the Bridger mine in 2023?

A. About [redacted] tons.[47] This includes about [redacted] base tons and [redacted] supplemental tons.[48]

Q. Are there alternative Bridger mine production scenarios that PacifiCorp considered?

A. Yes. Outside of the LTFSP, PacifiCorp did consider a scenario where only [redacted] tons was produced each year,[49] or about [redacted] percent less than the proposed 2023 level. However, it is unclear what economic analysis, if any, PacifiCorp undertook to evaluate this option.

Q. At PacifiCorp's proposed production rate of [redacted] tons, how many more years would be needed to produce the remaining [redacted] tons of additional coal that Jim Bridger needs to operate from 2023-2037?

A. Less than [redacted] years. This suggests that the Bridger mine could conceivably cease production as soon as [redacted] without threatening grid reliability since the Jim Bridger plant would still have enough fuel to operate through 2037, under the IRP No Minimum Scenario. This is true even without securing any additional coal fuel sources such as from Black Butte or southern Powder River Basin.

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[47]Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.9 "Attach SC 2.9 CONF" [hereinafter "Attach SC 2.9 CONF "] (attached as Exhibit Sierra Club/113).
[48] *Id.*
[49] *Id.*

Q. Is there sufficient storage capability to handle this scenario?

A. Yes. According to PacifiCorp, the maximum storage capacity at the BCC mine is 1.9 million tons[50] and the Jim Bridger plant has an additional 1.5 million tons of storage capacity,[51] for a combined total of 3.4 million tons. Meanwhile, the IRP No Minimum Scenario model run shows that of the [redacted] total tons needed from 2023-2037, an estimated [redacted] tons would be consumed in 2023 leaving the remaining [redacted] tons to be consumed in the subsequent years.[52] This roughly [redacted] to the combined storage capacity of the plant and mine.

Q. What are the implications of this for future TAM proceedings?

A. There are a few implications. First it suggests that it may be prudent to accelerate closure of the Bridger mine before the planned 2028 exit date, and possibly in the [redacted] timeframe. Second, it means that PacifiCorp should begin to minimize new capital investments and other incremental fixed costs at the mine immediately. Third, it means that the Commission may want 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.

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

A. My recommendations are as follows:

1. The Commission should require fundamental changes to the 2022 LTFSP. While a revised LTFSP should be completed as soon as possible, I recognize that it may be most practical to require an updated LTFSP in the 2024 TAM. I recommend that the

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[50] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 2.12.
[51] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 2.13.
[52] Author's calculation. LTFSP Comparison_HIGHLY CONF (Burgess).

Commission also require an updated long-term fuel plan for Jim Bridger in every subsequent TAM proceeding.

2. Future iterations of the LTFSP should use modeling software capable of handling multiple fuel tiers, such as PLEXOS, which the Company used to evaluate the Naughton CSA, or Aurora.

3. Additionally, future iterations should include a scenario without any coal from Black Butte or any minimum take assumptions from BCC.

4. Finally, future LTFSP iterations should be required to evaluate a scenario where no new coal is sourced after [redacted] and Jim Bridger relies on stockpiled coal through 2037.

V. Proposed Jim Bridger Costs Included in the 2023 TAM

Q. Is PacifiCorp seeking to include fuel costs for the Jim Bridger coal plant in this year's 2023 TAM?

A. Yes. PacifiCorp's 2023 TAM application includes fuel costs for Jim Bridger from both the third-party owned Black Butte mine and the Company-owned Bridger mine.

A. Black Butte Fuel Costs

Q. Is PacifiCorp's application seeking cost recovery in the 2023 TAM for anticipated Black Butte costs under a future CSA?

A. Yes. PacifiCorp had previously indicated that it plans to execute a new CSA with Black Butte in May 2022 to supply the Jim Bridger plant.[53] Because the details of this contract were not final at the time of PacifiCorp's application in March 2022, the Company was only able to provide speculative information about future Black Butte fuel costs in its application for the Commission's review. These speculative Black Butte costs are embedded in PacifiCorp's projected 2023 NPC included in the TAM application. More specifically, PacifiCorp said: "The Black Butte price for 2023 is estimated at $[redacted] per ton due to recent increases in market coal prices. This estimate will be updated if a new contract is executed through the upcoming TAM update."[54] As a result, while PacifiCorp is not seeking to include the exact contract costs into rates at this time, it is seeking approval of future Black Butte costs that it anticipates might be in effect through 2023.

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 2023 TAM?

A. Not to my knowledge. PacifiCorp's testimony simply stated that "[d]elivered costs for the [redacted] of Black Butte coal increased from $[redacted] in the 2022 TAM to

[53] *In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, Proceeding No. A.21-08-004, PacifiCorp (U 901 E) Brief Summary of Dates that Existing Coal Supply Agreements Are Scheduled for Renewal (Cal.P.U.C. Nov. 10, 2021), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M425/K516/425516818.PDF.
[54] PAC/200 at Owen/18:16-19.

$[redacted] in the 2023 TAM, or $[redacted] overall."[55] However, no supporting workpapers or analysis were provided to explain how this volume and pricing were estimated. Notably, all five scenarios evaluated in PacifiCorp's LTFSP assumed exactly [redacted] tons (base quantity) of Black Butte coal would be delivered in 2023,[56] but that Plan did not include any analysis for how the Black Butte volume and pricing were originally estimated. In summary, PacifiCorp seeks to recover over $[redacted] in the 2023 TAM for coal fuel from Black Butte that it provided no justification for in its application.

Q. How has PacifiCorp characterized future Black Butte coal costs in other recent proceedings?

A. In the most recent California ECAC proceeding (which is analogous to the TAM) PacifiCorp confirmed that its estimated Black Butte prices were not developed based on historical pricing from these sources.[57] Instead, they were developed "based on conversations with the coal suppliers and the Company's professional judgement."[58] In other words, the estimated future prices are not merely hold-overs or placeholders based on recent pricing. Instead, they are the Company's best guess at what future prices are likely to be. Notably, that forecasted pricing included minimum take requirements that PacifiCorp assumed would be required under a new CSA.[59]

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[55] *Id.* at Owen/18:11-12; Confidential PacifiCorp Response to Sierra Club Data Request 3.2(a) (attached as Exhibit Sierra Club/114) (noting that the $[redacted] per ton price represents "just the coal supply agreement" and the $[redacted] per ton price represents "the full delivered cost of coal including transportation").
[56] Highly Confidential Bridger LTFSP at Apps. 13-17.
[57] PacifiCorp Response to Sierra Club Data Request 7.1 in Cal. Pub. Util. Comm'n. Proceeding No. A.21-08-004. Public data responses from A.21-08-004 referenced herein are compiled and attached as Exhibit Sierra Club/115; Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 5.4(a).
[58] Sierra Club/115, PacifiCorp Response to Sierra Club Data Request 6.2(b) in A.21-08-004.
[59] *Id.* at 6.2(e).

Q. How did PacifiCorp estimate 2023 fuel costs for Black Butte and any alternatives?

A. Sierra Club has only limited knowledge of any steps that PacifiCorp took to evaluate other coal purchasing options from Black Butte in 2023 besides the volume and price specified in its application. In response to Sierra Club Data Request 5.4, PacifiCorp stated that its volume estimate was "informed by several iterative AURORA model runs for this 2023 [TAM]" and the Company's "professional judgment" but it is not clear if different volumes or prices were considered. Outside of these "iterative" runs for the 2023 TAM, PacifiCorp does not appear to have developed any generation forecasts specifically for the purpose of evaluating different Black Butte contract scenarios and further does not appear to have considered any alternatives to purchasing approximately [redacted] tons of coal from this source. Even in the updated LTFSP, PacifiCorp assumed Black Butte was a fuel source in all scenarios evaluated rather than considering scenarios where the Black Butte contract was not renewed. Moreover, the 2023 base volume ([redacted] tons) was [redacted]. Furthermore, it appears that PacifiCorp did not model the full delivered price of Black Butte coal in its Aurora model runs for the 2023 TAM, [60] even though that is the Company's standard practice for evaluating required coal volumes under new coal supply agreements.

Q. What rationale has PacifiCorp given for the need to procure fuel from Black Butte in 2023 and beyond?

A. It is unclear. As noted above in context of the LTFSP, when asked by Sierra Club why the Company did not evaluate a scenario without Black Butte, the Company's response simply confirmed that every scenario they evaluated "required" this fuel source and that

[60] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 5.4(d).

"[t]he Bridger Coal Company (BCC) underground mine shuttered in 2021 which reduced BCC's total production capacity."[61] However, the results of the No Minimum Scenario, which I described directly above in Section IV and describe in more detail in Section VI(A), contradict the assumption that Black Butte coal is needed. Under this scenario, PacifiCorp demonstrated that the Jim Bridger plant could operate through 2037, while maintaining grid reliability, even without the "required" quantity fuel of that Black Butte would supply. Moreover, PacifiCorp already has and is likely to maintain a significant stockpile of coal fuel at the Bridger plant and Bridger mine, that could be drawn upon in case generation needs are higher than anticipated.

Q. In your opinion, has PacifiCorp demonstrated that its anticipated 2023 Black Butte fuel costs are reasonable?

A. No, I do not believe that PacifiCorp has demonstrated the prudency of these anticipated costs, particularly because there is evidence described throughout my testimony suggesting that PacifiCorp does not require *any* coal from Black Butte in 2023.

Q. What action do you recommend the Commission take regarding the estimated costs associated with the expected Black Butte CSA, for which the terms have not been finalized nor reviewed by the Commission?

A. I recommend that the Commission exclude the estimated Black Butte costs from TAM rates until the Commission has had an opportunity to review further analysis from PacifiCorp demonstrating the prudency of a new Black Butte CSA.

[61] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 4.7.

B. Bridger Coal Company Mine Fuel Costs

Q. In addition to Black Butte, do you have any additional concerns regarding the recovery of Jim Bridger coal fuel costs in the 2023 TAM?

A. Yes. In addition to Black Butte, PacifiCorp is also seeking cost recovery for BCC mining costs, 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 and did not demonstrate sufficient efforts to minimize BCC costs in those proceedings, it is particularly important for the Commission to exercise its authority to review the reasonableness of BCC expenses.

Q. How does BCC/PacifiCorp project production costs at the BCC mine, including those for 2023?

A. Each year, BCC/PacifiCorp develops an annual mine plan for the BCC mine that includes the total production costs it expects to incur in the following year and will ultimately be charged to PacifiCorp customers through the TAM.[62] However, PacifiCorp's application did not provide any supporting analysis to justify the 2023 BCC production volumes in the same manner it did for other new CSAs in this proceeding (e.g., for Naughton) or past TAM proceedings (e.g., Hunter and Dave Johnston in the 2022 TAM).

[62] *See In the Matter of In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, Proceeding No. A.21-08-004, Rebuttal Testimony of James Owen (PAC/800) at Owen/14:21-15:10 (May 2022), *available at* https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2108004/5010/475764908.pdf [hereinafter "2022 ECAC PAC/800"].

Q. Did PacifiCorp's Application in this case include the BCC mine plan for 2023, including a detailed budget showing the BCC-related costs it expects to incur in 2023?

A. No. However, the 2023 BCC mine plan was eventually provided in response to Sierra Club Data Request 3.6. Notably, the "plan" the Company provided consists solely of a simple budget table in Microsoft Excel for a single production volume costing over $[redacted] with no narrative description or other supporting documentation.[63] Once again, this spreadsheet was not included in PacifiCorp's 2023 TAM application. Notably, PacifiCorp does not even anticipate finalizing its 2023 mine plan until Q4,[64] potentially well after a decision in this proceeding.

Q. How has PacifiCorp's responded to Sierra Club's inquiries about the cost implications of operating the BCC mine at a significantly reduced output level?

A. PacifiCorp stated that "[o]perating the mine on a significantly reduced level (e.g. 50% lower) has not been evaluated"[65] and "[i]t is impractical to speculate how materials and supplies expenses would be impacted in a one-year plan."[66]

Q. What is your assessment of this response?

A. It strikes me as disingenuous since Sierra Club has identified the high cost of BCC coal over the last several TAM cycles. Yet, as the Company has done in prior TAM proceedings, PacifiCorp continues to express a limited ability to consider cost reductions due to the perceived limits of a "one-year plan." This suggests that, in each TAM,

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[63] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 3.6 "Attach SC 3.6 CONF" [hereinafter "Attach SC 3.6 CONF"] (attached as Exhibit Sierra Club/116).
[64] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 5.3(a).
[65] Sierra Club/105, PacifiCorp Response to Sierra Club Data Requests 3.9. *See also* Sierra Club/105, PacifiCorp Responses to Sierra Club Data Requests 3.12, 3.13, and 3.14.
[66] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 3.9.

PacifiCorp willfully avoids any long-term fuel planning considerations at BCC which could benefit its customers. This is particularly problematic because the Company did not prepare any long-term planning for BCC in its most recent 2021 IRP, even though doing so would have also allowed the Company to evaluate prudent coal consumption at the plant in advance of the Black Butte contract expiration date. While PacifiCorp has pointed to its 2023 IRP as the appropriate time to evaluate long term planning for Jim Bridger's fueling,[67] there is no reason why comprehensive planning should wait until the next IRP cycle. Notably, delaying evaluation of alternative fueling for Jim Bridger until the 2023 IRP would conveniently occur *after* PacifiCorp plans to sign a new Black Butte contract and potentially after PacifiCorp seeks to include the Black Butte contract costs into rates.

If the Company is unable to consider fuel costs beyond a 1-year time horizon in the TAM and has also failed to evaluate fuel costs in its long-term IRP proceedings (e.g., during the 2021 IRP), then it is not acting prudently to ensure just and reasonable rates. Furthermore, PacifiCorp has provided evidence that it can still meaningfully adjust some of its costs (e.g., labor) within the one-year time horizon.[68] This contrasts with last year's TAM where PacifiCorp claimed that most BCC production costs, including labor, were entirely fixed.

[67] 2022 ECAC PAC/800 at Owen/17:1-3.
[68] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 3.8(b).

Q. Despite these responses, do you think PacifiCorp actually *has* evaluated different production scenarios for BCC in 2023?

A. Yes. Through a response to discovery requests from Sierra Club, PacifiCorp did eventually provide a list of BCC production scenarios it has recently considered;[69] however, this did not include a detailed explanation of how PacifiCorp initially developed these scenarios, how the Company evaluated and compared these options, or how it ultimately selected one. Notably, PacifiCorp's response to this discovery request showed that there are significant differences in cost between the various base BCC production scenarios the Company considered, with total costs ranging from $[redacted] to $[redacted]. Furthermore, PacifiCorp appears to have excluded some of these lower cost options from its 2023 TAM evaluation, though it is unclear to me why they did so. For instance, the plan labeled "Opt. 3a 2.8 Plan – Nov 4.0 Fcst" would be approximately $[redacted] less than the base plan PacifiCorp ultimately selected for the 2023 TAM. It is true that the Opt. 3a 2.8 Plan would produce [redacted] fewer tons of base coal than PacifiCorp's preferred plan, and that this differential would need to be replaced by energy from another source. However, PacifiCorp has not demonstrated that such replacement energy would incur higher costs for its customers. For example, if the replacement energy came from an energy source with costs equivalent to the BCC Supplemental Coal (i.e., price of $[redacted]), then the Opt. 3a 2.8 Plan would still be less expensive. Notably, such a scenario would be similar to [redacted].

[69] Sierra Club/113, Attach SC 2.9 CONF.

Confidential Table 4. Bridger Coal Mine Plans Provided in Response to Sierra Club Data Request 2.9

Bridger Coal Mine Plans (base plan for 2023 TAM *in italics and bold*)	**Delivered Tons**	**$/ton**	**Total Cost ($M)**
Opt. 1 3.78 Plan - Jun Fcst	[redacted]	[redacted]	[redacted]
Opt. 1&2H 3.38 Plan - Jun Fcst	[redacted]	[redacted]	[redacted]
Opt. 2 3.38 Plan - May Fcst	[redacted]	[redacted]	[redacted]
Opt. 2 3.38 Plan - Jun Fcst (PAC Budget)	[redacted]	[redacted]	[redacted]
Opt. 2 3.38 Plan - Jun Fcst	[redacted]	[redacted]	[redacted]
Opt. 3a 2.8 Plan - Jun Fcst	[redacted]	[redacted]	[redacted]
Opt. 3b 2.20 Plan - Jun Fcst	[redacted]	[redacted]	[redacted]
Opt. 4 3.38 Plan - Jun Fcst	[redacted]	[redacted]	[redacted]
Opt. 1&2H 3.38 Plan - Nov 4.0 Fcst	[redacted]	[redacted]	[redacted]
Opt. 1&2H 3.38 Plan - Nov 4.3 Fcst	[redacted]	[redacted]	[redacted]
Opt. 2 3.38 Plan - Nov Fcst	[redacted]	[redacted]	[redacted]
Opt. 3a 2.8 Plan - Nov 4.0 Fcst	[redacted]	[redacted]	[redacted]
Opt. 3a 2.8 Plan - Nov 4.3 Fcst	[redacted]	[redacted]	[redacted]
Opt. 4 3.38 Plan - Nov Fcst	[redacted]	[redacted]	[redacted]

Q. Did PacifiCorp's 2022 LTFSP for the Bridger plant include any analysis of BCC coal in 2023?

Yes. However, the 2022 LTFSP has a variety of limitations as described above in Section IV. Furthermore, the LTFSP included a very limited number of production scenarios for the Bridger mine in 2023, which are summarized in the table below. Notably, all the LTFSP Scenarios include BCC volumes that differ from the 2023 BCC plan proposed by PacifiCorp for the 2023 TAM, which calls for [redacted] tons in 2023 (PacifiCorp's share).[70]

[70] *Id.*

Highly Confidential Table 5. LTFSP and 2023 TAM BCC Mine Production Scenarios

Scenario	Delivered Tons (millions) 2023--PacifiCorp's Share		
	BCC Base	BCC Supplemental	Total
LTFSP Scenario 1 (Black Butte)	[redacted]		
LTFSP Scenario 2 (SPRB)			
LTFSP Scenario 3 (Bridger low)			
LTFSP Scenario 4 (Bridger med)			
LTFSP Scenario 5 (Bridger high)			
BCC Operating Plan for 2023 TAM			

Q. Just to confirm, PacifiCorp is proposing a BCC mine plan for the 2023 TAM that not consistent with any of the scenarios in the LTFSP?

A. Correct. In fact, PacifiCorp stated that its preferred LTFSP scenario [redacted][71]

Q. Do any of the BCC base volumes evaluated in the LTFSP or presented in SC 2.9, reflect the lower end of BCC's possible production range?

A. No. In its LTFSP, PacifiCorp states that "[redacted]"[72] As noted above, this means that PacifiCorp's share (66.7%) of the lower end of the production range (i.e., [redacted] tons) would be [redacted]. However, the LTFSP did not analyze any scenarios as low as [redacted] base tons.

[71] Highly Confidential PacifiCorp Response to Sierra Club Data Request 5.8(c) (attached as Exhibit Sierra Club/117).
[72] Highly Confidential Bridger LTFSP at 7.

Q. Has Sierra Club attempted to discern whether PacifiCorp conducted any further analysis of different BCC production options in this or other recent proceedings?

A. Yes. In the 2022 California ECAC, Sierra Club requested that PacifiCorp "identify the range of production and coal delivery levels considered when developing the base BCC mine plan for the 2020, 2021, and 2022 ECACs." PacifiCorp responded, "[t]here are no ranges of production and coal delivery levels that are considered specifically for PacifiCorp's ECAC proceedings."[73] Notably, this response is at odds with the information provided in response to Sierra Club Data Request 2.9 in this proceeding, which indicates that PacifiCorp actually *had* considered a range of potential BCC production options prior to the 2022 ECAC proceeding (even though these scenarios were not provided as part of its application or subsequent discovery requests). This indicates to me that PacifiCorp might be concealing information about its planning and analysis related to the BCC mine. At a minimum, the Company has not been very transparent about its approach to evaluating different BCC production levels and related costs.

Q. What BCC production levels did PacifiCorp consider prior to its application in this case?

A. The Company's response to Sierra Club Data Request 2.9 appears to provide a range of production scenarios that PacifiCorp considered. While this is helpful, it still does not provide any information about any analysis the Company performed on each of these scenarios to determine which one it would select as its "base plan" or preferred scenario, nor how these scenarios were determined.

[73] Sierra Club/115, PacifiCorp Response to Sierra Club Data Request 5.2 in A.21-08-004.

Q. Is the fact that PacifiCorp did not present the 2023 BCC operating plan to the Commission for review and approval concerning to you?

A. Yes. This is very concerning to me for several reasons. For example, BCC/PacifiCorp has discretion to adjust the annual BCC operating plan each year as it sees fit, including any increase or decrease in coal production volumes and costs that are ultimately reflected in the TAM. In essence, each annual BCC operating plan is the functional equivalent of a new contract that would generally require Commission review. Yet, PacifiCorp has not presented its 2023 BCC operating plan (including any alternative production volumes it may have considered) for Commission review in the current proceeding, or in any previous TAM.

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 I can think of 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.[74] 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

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[74] Notably, PacifiCorp has not considered other options for collecting revenue for mine reclamation activities. *See* Sierra Club/115, PacifiCorp Response to Sierra Club Data Request 2.10 in A.21-08-004.

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.

Q. What action do you recommend the Commission take regarding the estimated costs associated with the BCC 2023 Operating Plan, which have not been reviewed by the Commission?

A. I recommend that the Commission exclude the estimated BCC fuel costs from the 2023 TAM rates until PacifiCorp is able to provide sufficient justification for the production volume selected as part of the BCC base plan. Alternatively, the BCC fuel costs included in 2023 TAM rates should correspond to the quantity included in Scenario 5 of the LTFSP. Additionally, in each TAM going forward, PacifiCorp should be required to present a range of BCC mine plan options with different production volumes and a detailed analysis for the plan it ultimately selects. This plan should be consistent with the LTFSP.

VI. Recent Dispatch Model Runs Show that Significantly Reducing Jim Bridger Output (i.e., on the Order of [redacted] Percent) in 2023 Could Be Beneficial to Ratepayers

Q. You've discussed why PacifiCorp has not justified its proposed Black Butte and BCC fueling costs for the 2023 TAM. Are there any other reasons to doubt that the proposed fuel costs are just and reasonable?

A. Yes. Two modeling runs have been recently conducted providing evidence that Jim Bridger's true economic output is significantly lower than what has been presented in the 2023 TAM. These modeling runs used average costs at Jim Bridger, meaning that they provided evidence on what level of generation is economic when minimum take requirements no longer apply, such as the expiration of the Black Butte contract. These model runs suggest that economic generation at Jim Bridger significantly declines when the plant is no longer subject to minimum take requirements, as is the case in this TAM. Yet, PacifiCorp's application continues to forecast Jim Bridger generation roughly in line with generation from prior years.[75]

Q. Can you provide an overview of the recent dispatch model runs PacifiCorp performed showing reduced Jim Bridger output in 2023 and describe the details of each of them?

A. Yes. The first of these was a PLEXOS model run conducted as part of PacifiCorp's 2021 IRP proceeding, which is briefly discussed above. The second was an Aurora model run provided in this 2023 TAM proceeding using average costs. I will address the Aurora run first and then provide more information on the 2021 IRP No Minimum Scenario modeling, which I already briefly addressed above.

A. Average Cost Model Run for 2023 TAM

Q. Can you explain further why it is appropriate to consider the model run that used average costs when evaluating 2023 TAM costs at Jim Bridger?

A. Yes. When conducting a forward-looking analysis for Jim Bridger, the average cost better approximates the full cost of coal fuel than PacifiCorp's initial modeling approach which uses the mines' "incremental" pricing.[76] The average cost modeling approach is PacifiCorp's standard practice when evaluating a new CSA, which also relies on an

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[75] For comparison, the ORTAM22 NPC CONF workpaper shows [redacted] GWh of Jim Bridger generation in 2022, whereas the ORTAM23 NPC CONF workpaper shows [redacted] GWh of Jim Bridger generation in 2023 – a less than [redacted] percent reduction. ORTAM23 NPC CONF; Confidential Workpaper accompanying the Direct Testimony of David Webb (PAC/100) "ORTAM22 NPC CONF" in UE 390.

[76] In PacifiCorp's prior modeling software, GRID, the incremental price was represented in the "dispatch tier" price.

average cost input when conducting dispatch analysis. For BCC, completing a new annual BCC mine plan is analogous to entering into a new CSA each year. Meanwhile there is no existing Black Butte CSA for 2023. Thus, average costs for coal supply are appropriate when determining how much Jim Bridger generation—and in turn Black Butte and BCC coal production—is economic.

Q. Is the use of average fuel costs as an input for modeling Jim Bridger's dispatch in 2023 complicated by the fact that PacifiCorp expects the plant to be supplied by Black Butte coal in addition to BCC coal?

A. No. It is true that in previous years Jim Bridger was subject to a minimum take requirement due to a contract with the Black Butte mine. Thus, if there were a Black Butte contract that had already been executed and approved by the Commission for 2023, it may be appropriate to exclude the "minimum take" costs specified in that contract from the dispatch model. However, in the present proceeding there is neither an approved future Black Butte CSA for 2023 nor an approved 2023 operating plan for the Bridger mine. Therefore, an average cost run is a good approximation of economic coal consumption at Jim Bridger because neither the Bridger mine nor a future Black Butte CSA contain an existing minimum take provision, and therefore both should be modeled at average cost.

Q. What did the results of the Jim Bridger "average cost" dispatch model run in Aurora show for 2023 when compared to PacifiCorp's original model run using "incremental pricing"?

A. The results show a decrease in Jim Bridger dispatch of about [redacted] percent relative to PacifiCorp's 2023 TAM proposal.[77]

Q. Does the AURORA model run using average costs provide evidence that the NPC would be lower if Jim Bridger's output were reduced by that amount in 2023?

A. Yes, there is evidence that the NPC could be reduced by approximately $[redacted] under this scenario with reduced Jim Bridger output. However, this finding requires a careful interpretation of the model results that PacifiCorp provided. This is because PacifiCorp made additional adjustments in the average cost model run beyond just the dispatch price. As such, it would be incorrect to simply compare the final NPC that PacifiCorp reported in the two model runs and conclude that the difference is due to changing the dispatch price alone.

Q. What other adjustments did PacifiCorp make in the average cost model run besides the dispatch price?

A. PacifiCorp included an additional fixed cost component for coal fuel supplying the Jim Bridger and Hayden plants, which is summarized below for the entire year. As the table indicates most of these fixed fuel costs are related to Jim Bridger.

[77] Author's calculation.

Confidential Table 6. Additional Fuel Costs by Plant

Plant	Additional Fixed Fuel Cost (2023)[78]
Jim Bridger	[redacted]
Hayden	[redacted]
Total	[redacted]

Q. Do you believe this fixed cost adjustment is appropriate in the case of Jim Bridger?

A. No. As I explained above, there are no existing minimum take requirements at Jim Bridger in 2023 that would necessitate such an adjustment. Thus, I believe it is not appropriate to include this additional cost when calculating the 2023 NPC. Once the adjustment is removed, the 2023 NPC of the average cost case decreases by about $[redacted] relative to PacifiCorp's proposed NPC.

Q. Has PacifiCorp previously disputed the notion that these fixed cost components are avoidable and should therefore be excluded?

A. Yes. PacifiCorp has previously argued that fixed costs—such as those associated with take-or-pay commitments at Black Butte or certain fixed costs at BCC—cannot be avoided. However, as I have discussed, there was no preexisting take-or-pay requirement for Black Butte in 2023 at the time of PacifiCorp's application since there was no executed contract. In addition, PacifiCorp has argued that certain fixed costs at the Bridger mine might not be recovered in a low production scenario, and/or that the Bridger mine could not ramp down production to a significant extent.[79]

[78] Confidential workpaper accompanying PacifiCorp's 2023 TAM Application "ORTAM23 Average Fuel Cost Final NPC CONF" included in "OR UE-400 CONF 15-CalDay Work Papers."
[79] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390 (PAC/1000) at Staples/20:1-21:18 (Aug. 2021), *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue390htb112353.pdf.

Q. Does Sierra Club believe PacifiCorp's inclusion of additional fixed costs at this level is appropriate?

A. No. PacifiCorp has not demonstrated that these future costs are truly fixed and could not have been reduced or eliminated in advance of the 2023 operating year.

Q. Can you summarize your previous arguments for why these fixed costs should be reduced or eliminated?

A. Yes. The fixed costs PacifiCorp assumes in 2023 are mainly related to the Jim Bridger plant. However, for both of Jim Bridger's fuel sources, there were little to no costs that were predetermined for 2023 at the time PacifiCorp filed its application. First, as discussed earlier in my testimony, there is currently no executed CSA for Black Butte in 2023. It has become apparent in this proceeding that PacifiCorp/BCC has evaluated multiple base plans for BCC, some of which include lower total production and cost.[80] Second, PacifiCorp has substantial discretion over the costs incurred to operate the Bridger mine in 2023 and could have reduced these costs in advance (including those that would become "fixed" in 2023) if it anticipated lower output from the plant. PacifiCorp has stated that it is able to adjust scheduled operations at the mine and thus "fixed" costs, such as labor, can be adjusted within the operating year.[81] Accordingly, opportunities for reducing costs exists, as PacifiCorp itself acknowledged in its 2021 IRP proceeding that "a lot of things" can be done and there are "opportunities[82]

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[80] Sierra Club/113, Attach SC 2.9 CONF. *See also* Confidential Table 4, Bridger Coal Mine Plans Provided in Response to Sierra Club Data Request 2.9.
[81] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 3.8(b).
[82] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, PAC 2021 IRP Commission Workshop Video Recording at 2:43:51-2:44:26 (MacNeil, PacifiCorp) (Jan. 13, 2022), *available at* https://www.oregon.gov/puc/news-events/Pages/default.aspx.

Q. If the additional fixed cost adjustment is removed, how does the 2022 NPC for the average cost Aurora model run compare to PacifiCorp's original model run?

A. I estimate that the 2022 NPC is about $[redacted] lower in the average cost model run than in PacifiCorp's original model run. The primary contributor to these savings is reduced output from the Jim Bridger plant, which I mentioned was about a [redacted] percent reduction.

B. 2021 Integrated Resource Plan Model Run

Q. Are there any other relevant generation forecasts for Jim Bridger that were recently completed?

A. Yes. As previously discussed in Section IV, in PacifiCorp's 2021 IRP, the Company produced a portfolio sensitivity that removed minimum take requirements for coal fuel supplying Jim Bridger ("No Minimum Scenario").

In PacifiCorp's "preferred portfolio," the Company assumed that Jim Bridger would be subject to minimum take requirements from both the Black Butte and Bridger mines for many years, despite the fact that there is no contract for Black Butte coal after April 2022 and the Company controls production at Bridger. Both Sierra Club and Oregon Commission Staff raised concerns with the minimum take assumptions at Jim Bridger, which prompted PacifiCorp to run a sensitivity without those constraints, making the modeling similar to the "average cost" runs described above.[83] However, this IRP modeling was completed with PLEXOS software, rather than Aurora or GRID, and was produced to forecast anticipated generation at Jim Bridger over the 20-year IRP planning

[83] PacifiCorp Response to ALJ Bench Request 1, 6, 7 in LC 77 (provided as attachments to the PacifiCorp Response to Sierra Club Data Request 2.16) (attached as Exhibit Sierra Club/118).

period, rather than the 1-year NPC forecast developed for this proceeding. While I recognize these differences, the IRP modeling is extremely relevant to the prudency of the BCC operating plan, as it informs what level of production at BCC, which then is translated into NPC in this proceeding, is in the best interest of ratepayers.

Q. Can you summarize the findings of the No Minimum Scenario from PacifiCorp's 2021 IRP?

A. Yes. The findings are significant. Compared to PacifiCorp's preferred portfolio, annual generation at Jim Bridger Units 3 and 4 was reduced by [redacted] percent, on average, between 2022 and 2037.[84] In 2023, this reduction was about [redacted] percent, meaning that the current BCC mine plan would be impacted..[85] After 2030, there was [redacted] output from the plant.[86] As a result, the No Minimum Scenario clearly would require significantly lower levels of production from BCC and/or purchases from Black Butte to meet the lowered generation output. Moreover, the results showed significant customer savings: compared to PacifiCorp's top performing portfolio, the No Minimum Scenario reduced the "present value of revenue required" ("PVRR") by $156 million.[87]

Q. Did PacifiCorp dispute whether the No Minimum Scenario was feasible?

A. Yes. PacifiCorp asserted that it would be "unrealistic" for its current suppliers (e.g., Black Butte and BCC) to deliver significantly lower volumes of coal and/or produce coal

[84] Author's calculation. *See* Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.16 "Attach ALJ Bench Request 1-1 CONF" at Tab "OR study JB No Minimum" (Jim Bridger generation forecast under the No Minimum Scenario.) (attached as Exhibit Sierra Club/119). Please note that the "ST Model" forecast depicts final, estimated generation from Jim Bridger 3 and 4.
[85] *Id.*
[86] *Id.*
[87] Sierra Club/118, PacifiCorp Response to ALJ Bench Requests 1.

without take or pay provisions.[88] As a result, PacifiCorp theorized that it would need to retrofit Jim Bridger to process coal from the Powder River Basin ("PRB"), which would cost approximately $[redacted] (PVRR), thereby [redacted] the $156 million PVRR benefit.[89]

Q. Do you agree that PacifiCorp would likely need to retrofit Jim Bridger to accept PRB coal?

A. No. I disagree for two reasons. First, PacifiCorp's LTFSP includes several scenarios that avoid this capital investment. In fact, this is one of the benefits the Company touts for its preferred Scenario 5.[90] Second, as explained earlier, I estimate that only about [redacted] tons of coal are needed *in total* to supply Jim Bridger from 2023 through 2037 under the No Minimum Scenario. This is approximately what PacifiCorp could reasonably expect to mine from BCC *alone* over the next [redacted] years. Notably, supply would largely not be needed for Units 1 and 2, because PacifiCorp seeks to convert those units to gas in 2024.[91] Thus, it is conceivable that PacifiCorp could continue BCC mine production through [redacted] at current production levels and produce enough coal to operate Jim Bridger through 2037. This would avoid the need to enter any long-term contracts with minimum take obligations.

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88 *Id.*
89 Sierra Club/118, Confidential PacifiCorp Response to ALJ Bench Request 1.
90 Sierra Club/104, Redacted Bridger LTFSP at 6.
91 *See, e.g.*, PacifiCorp, *2021 Integrated Resource Plan*, Vol. I at 15 (Sept. 1, 2021), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.

C. Assessment of Jim Bridger Fuel Costs Based on Recent Dispatch Model Runs

Q. The model results you described above suggest a lower output from Jim Bridger (and in turn lower BCC output) would be beneficial in 2023. Doesn't the 2023 BCC operating plan forecast reduced BCC coal volumes relative to 2022?

A. Yes. However, the projected reduction from 2022 to 2023 is only reduced by approximately [redacted] percent,[92] far less than the [redacted] percent projected reduction shown in the economic dispatch modeling results I described above for Jim Bridger.

Q. What is your overall assessment of PacifiCorp's proposed Jim Bridger fuel costs in 2023?

A. My assessment is that PacifiCorp has not demonstrated the prudency of its proposed Jim Bridger fuel costs for 2023. Previous modeling studies, including those in the 2023 TAM and 2021 IRP have suggested that it may be in PacifiCorp customers' best interest to reduce output from the Jim Bridger plant (and in turn the BCC coal volume) up to [redacted] percent on a going forward basis.[93] The degree to which this economic reduction will be realized going forward depends in part upon which BCC-related costs that PacifiCorp had previously identified as "fixed" within a one-year time horizon could be avoided in subsequent years, over multiple TAM cycles (including this one). Armed with knowledge from the previous ECAC and TAM proceedings and the current IRP proceeding that significant reductions could result in ratepayer savings, as well as this Commission's order that the Company carefully review alternatives prior to executing new coal supply agreements, I would have expected PacifiCorp to explore scenarios in each future TAM

[92] Authors calculation. Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.11 "Attach SC 1.11 CONF" (attached as Exhibit Sierra Club/120); Sierra Club/116, Attach SC 3.6 CONF.
[93] Similar studies were also completed in the 2021 ECAC, 2022 ECAC, and 2022 TAM.

application (including this one) where the BCC coal volume was substantially reduced, including on the order of [redacted] percent but also other amounts. What is *unexpected* is for the Company to project future TAM rates using a Bridger mine operating plan and assumed Black Butte contract that do not consider this level of reduction.

VII. PacifiCorp Used Inappropriate Minimum Take Requirements for Jim Bridger in Aurora

Q. You have testified that PacifiCorp has not provided sufficient justification for its proposed Black Butte and BCC fuel purchases. Did PacifiCorp assume that these anticipated purchases were minimum take requirements in Aurora for forecasting the Company's 2023 NPC?

A. Yes. According to PacifiCorp's workpapers,[94] PacifiCorp included a minimum take volume of [redacted] MMBtu, which equates to approximately [redacted] tons of coal. This suggests that PacifiCorp is modeling Jim Bridger in 2023 under the presumption it would be subject to a very large minimum take volume reflecting both the 2023 BCC base plan (approximately [redacted] tons) and a future Black Butte contract ([redacted] tons). PacifiCorp included this assumption despite the fact that no minimum quantities existed for either fuel source for 2023 at the time of its application.

[94] Confidential Workpaper accompanying PacifiCorp's 2023 TAM Application "Aurora GN Fuel Prices CONF" included in folder "OR UE-400 CONF 5-BD Work Papers."

Q. You described in Section IV some differences between Aurora and GRID, including Aurora's ability to accept multiple price tiers. Is PacifiCorp able to more easily ensure that minimum take requirements are met through Aurora?

A. Yes. Aurora uses take-or-pay constraints as inputs for TAM cost modeling[95] and prices take-or-pay coal quantities at $0/MMBtu, including for fuel supplies where take-or-pay requirements do not exist.[96] PacifiCorp's approach makes sense where an *existing* supply agreement contains a take-or-pay provision, however this approach is inappropriate for plants where there is no existing agreement and no minimum take in effect. For the 2023 TAM, and as discussed at length above, the latter is true for the Jim Bridger plant. Additionally, Aurora allows PacifiCorp to directly input volumetric constraints for its fuel sources, meaning that PacifiCorp to set minimum and maximum coal consumption at its generating resources.[97]

Q. How did the coal volume PacifiCorp/BCC selected in the BCC 2023 operating plan get treated in Aurora when PacifiCorp developed its NPC forecast?

A. The 2023 BCC coal volume was treated the same way as the take-or-pay minimum volumes included in PacifiCorp's other CSAs. This means that the Aurora model dispatches the Jim Bridger plant assuming a $0/MMBtu cost for BCC coal (as well as Black Butte coal) until the 2023 planned volumes are consumed.[98]

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[95] Sierra Club/115, PacifiCorp Response to Sierra Club Data Requests 1.5(a), 1.20(a) in A.21-08-004.
[96] Sierra Club/115, PacifiCorp Response to Sierra Club Data Request 1.4(a) in No. A.21-08-004.
[97] PAC/100 at Wilding/16:15-18
[98] Sierra Club/115, PacifiCorp Response to Sierra Club Data Request 1.4(a) in No. A.21-08-004.

Q. Do you think PacifiCorp's assumed minimum take volume of approximately [redacted] tons of coal at the Bridger plant was appropriate?

A. No. As mentioned, there is no minimum established for either Black Butte or BCC in 2023, so it would have been more appropriate to assume a minimum take volume of 0 tons when modeling the optimal dispatch and coal fuel consumption in 2023. In the alternative, the minimum take amount assumed for BCC should have been set to no higher than the lowest quantity of coal BCC required in order to justify operating in 2023. This would address PacifiCorp's argument that although BCC is able to flex production, it cannot flex to zero. While PacifiCorp does not appear to have identified minimum production at BCC, the lowest volume BCC mine plan provided in response to Sierra Club Data Request 2.9 identified [redacted] tons (PacifiCorp's share), or about [redacted] MMBtu. [redacted]. Moreover, as discussed above, this estimate is likely conservative because PacifiCorp's LTFSP suggests that BCC production could be as low as [redacted] tons (PacifiCorp's share).

Q. Has the Company transitioned to the Aurora model for all of its forecasts and planning decisions?

A. No. As I mentioned earlier, the Company still used GRID for its 2022 Jim Bridger LTFSP. PacifiCorp also used PLEXOS to evaluate the recently executed Naughton CSA, and it [redacted] to evaluate exiting the current Huntington CSA. Furthermore, PacifiCorp recently stated that Aurora "has not yet been used for coal contract negotiation generation forecasts or for the business plan. Plans are in place to transition over to use the AURORA model for coal contract negotiations and the business plan. This transition is expected to occur in 2022."[99]

Q. Do you have any recommendations based on this?

A. Yes. I recommend that in all future TAM proceedings, the Commission require PacifiCorp to model the NPC using a lower minimum take volume for Jim Bridger that reflects the lowest feasible base quantity production for BCC. For the 2023 TAM, this value should have been in the 0 to [redacted] MMBtu range. This would reflect the true minimum scenario for both the BCC mine (according to PacifiCorp's mine plans) and the fact that Black Butte has no pre-existing minimum.

VIII. <u>The 2023 TAM Rates Should be Adjusted to Account for Unapproved Jim Bridger Coal Fuel Expenses</u>

Q. Sections V-VII of your testimony have explained why PacifiCorp has not justified its estimated coal fuel costs for either Black Butte or Bridger Coal Company. Can you please reiterate your recommendation here on how the Commission should address these costs?

A. Yes. As I've stated above, The Commission should not approve the estimated 2023 costs for Black Butte and BCC, as PacifiCorp has not shown that those costs are prudent. If PacifiCorp moves forward with new a CSA from Black Butte and its proposed 2023 BCC operating plan, PacifiCorp may seek recovery of those costs in future TAMs or the PCAM, but this should be approved only after the Commission has had the opportunity to review the new contract and the BCC operating plan.

[99] Sierra Club/115, PacifiCorp Response to Sierra Club Data Request 1.24 in Proceeding No. A.21-08-004.

Q. Have you estimated how excluding the Black Butte CSA as well as the 2023 BCC costs would affect the 2023 NPC and TAM rates?

A. Yes. As depicted in Confidential Table 7, if Black Butte and BCC costs were excluded, I estimate that the 2023 NPC would be reduced by approximately $[redacted]. The Oregon-allocated portion of the NPC would decrease by approximately $[redacted], or about [redacted] percent.

Confidential Table 7. PacifiCorp vs. Sierra Club 2023 TAM Calculation

	2023 TAM	2023 OR Allocated TAM
PacifiCorp Calculation	[redacted]	
Sierra Club Calculation		
Difference ($)		
Difference (%)		

Alternatively, if the Commission is inclined to grant recovery for BCC fuel costs in the 2023 TAM, I recommend that these costs should, at a minimum, be consistent with PacifiCorp's preferred Scenario 5 of the LTFSP. In combination with the removal of Black Butte costs, this would reduce the NPC by $[redacted]. The Oregon-allocated portion of the NPC would decrease by approximately $[redacted], or about [redacted] percent.

Highly Confidential Table 8. PacifiCorp vs. Sierra Club 2023 TAM Calculation, Alternative Recommendation

	2023 TAM	2023 OR Allocated TAM
PacifiCorp Calculation	[redacted]	
Sierra Club Calculation		
Difference ($)		
Difference (%)		

Q. Would either of these exclusions eliminate all future recovery of prudent costs for the Black Butte CSA or BCC production fuel sources in future years?

A. No. However, for 2023, PacifiCorp did not present a credible analysis to support either of these fuel costs in this case. The essential component is that ratepayers are only responsible, at any point, for costs which PacifiCorp has demonstrated are prudent and the Commission has reviewed and found to be prudent. PacifiCorp's proposed 2023 TAM rates includes estimated future coal costs without a complete analysis of alternatives and represent anticipated, future CSA costs that the Commission has not reviewed nor deemed prudent.

Q. If the Commission chooses not to exclude PacifiCorp's projected costs for Black Butte and the 2023 BCC operating plan, do you have an alternative recommendation?

A. Yes. In the alternative, the Commission should make clear that any approved rate recovery of these estimated costs is still "at risk" for PacifiCorp pending future Commission review of the final CSAs and operating plan. For example, if the Commission approves PacifiCorp's estimated Black Butte coal costs in the 2023 TAM, it should be clear that it could still determine at a later date that up to 100 percent of the actual Black Butte CSA costs were imprudent. If this were to occur, it would require a significant downward adjustment in the Power Cost Adjustment Mechanism to refund ratepayers for the estimated Black Butte coal costs that were approved in the 2023 TAM but subsequently deemed imprudent.

IX. Naughton Fuel Costs

Q. Is PacifiCorp seeking cost recovery for coal fuel associated with a new CSA at the Naughton plant executed in December 2021?

A. Yes.

Q. Have you reviewed the analysis the Company provided in its evaluation of the Naughton CSA?

A. Yes. This was provided in Exhibit PAC/201 accompanying the Direct Testimony of James Owen.

Q. What is your general impression of this analysis?

A. I believe this analysis is relatively sound. In particular, I support PacifiCorp's use of the PLEXOS model[100] with inputs roughly consistent with the 2021 IRP. This contrasts with the analysis PacifiCorp performed for coal supplies for the Jim Bridger and Huntington plants. I do not believe the Jim Bridger and Huntington plant analyses were as robust as that for Naughton.

Q. Are there features of the Naughton CSA that you believe are beneficial relative to other CSAs?

A. Yes. I believe the relatively low minimum take volumes are beneficial for PacifiCorp customers.

Q. Do you have any concerns about the Naughton CSA and related analysis?

A. Yes. I have two main concerns. My first concern relates to the scenarios evaluated in Exhibit PAC/201. Specifically, I am concerned that each of the scenarios evaluated (i.e.,

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[100] Sierra Club/105, PacifiCorp Response to Sierra Club Data Request 2.2 ("The dispatch analysis for the Naughton coal supply agreement (CSA) was performed in the PLEXOS model.").

[redacted]) each include multiple changes making it difficult to evaluate the effects of each individual change. For example, the [redacted] includes both the addition of [redacted], as well as [redacted]. In comparison, [redacted]. These two changes would appear to counteract each other from a cost perspective, and thus it is difficult to interpret the final results. I believe that superior approach would have been to limit the number of input changes for each scenario.

Q. What is your second concern about the Naughton CSA?

A. My second concern is the fact that the Naughton CSA appears to have [redacted].[101] Given that the [redacted] and could subject PacifiCorp customers to unexpected price increases. While the threshold of [redacted] is significantly higher [redacted], it is not much higher than [redacted] when the contract was executed.

Q. Do you have any recommendations based on these observations of the new Naughton CSA?

A. Yes, I have two recommendations. First, going forward, PacifiCorp should provide more transparency, in advance, regarding the scenarios it intends to use to evaluate new CSAs. At a minimum, PacifiCorp should provide a list of the key assumptions that differ between the scenarios. Second, I recommend that if the [redacted] is

[101] PAC/201 at Owen/2.

triggered, the Commission should evaluate whether any increased cost could have reasonably been avoided through alternatives.

X. Huntington Analysis

Q. Have you reviewed the analysis provided by PacifiCorp regarding the early termination of the Huntington CSA?

A. Yes.

Q. What is your assessment of this analysis?

A. This assessment is very limited in many ways. First and foremost, it [redacted][102] In fact, the analysis seems fixated on [redacted], rather than exploring other solutions.

Q. What would have been a better approach in your opinion?

A. A better approach would have been to [redacted]

[102] PacifiCorp, Highly Confidential Analysis of the Costs and Benefits of Exercise of the Environmental Review Clause in the Huntington Coal Contract (Apr. 28, 2022).

[redacted]

Q. Are you concerned that the existing minimum take constraint at Huntington is leading to excessive coal consumption compared to a scenario where that minimum take did not exist?

A. Yes. This was addressed by the Commission in its 2022 TAM order, where the Commission found that "PacifiCorp has had to make manual adjustments in GRID for each of the last four years to account for Huntington's minimum take requirement."[103] The Commission further noted that PacifiCorp's own witness acknowledged that multiple years of forcing burns in GRID to account for a minimum take requirement indicates that the minimum take requirement is not economic.[104]

Q. What is your recommendation to the Commission?

A. I recommend that the Commission direct PacifiCorp to supplement its analysis with additional modeling as I have described above.

Q. Does this conclude your testimony?

A. Yes.

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[103] Order No. 21-379 at 22.
[104] *Id.*

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/101

Exhibit Accompanying the Opening Testimony of Ed Burgess

Curriculum Vitae of Ed Burgess

Edward Burgess

eburgess@strategen.com
941-266-0017

Overview

Ed Burgess is Senior Director of Strategen Consulting's Government and Utility Consulting Practice. His core expertise is in policy and regulation of the electric power sector at the state level, with a specialized focus on economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design. Ed has served clients in the renewable energy, energy storage, electric vehicle, and energy efficiency industries, including several private companies, energy project developers, trade associations, utilities, government agencies, and foundations. His technical analysis has helped to shape state regulations and policies related to energy portfolio standards, distributed energy resources, rate design, resource planning and transmission/distribution system planning. Prior to joining Strategen, Ed played a lead role in two major initiatives at Arizona State University: The Utility of the Future Center and the Energy Policy Innovation Council where he conducted research and policy analysis for the Governor's Office of Energy Policy, the Department of Environmental Quality, and other major stakeholders in Arizona. Ed also worked as an independent consultant for Schlegel & Associates, providing technical analysis on demand-side management policies, and for Kris Mayes Law Firm providing regulatory support to the solar industry in the Southwest U.S.

Senior Director
AUG 2019 – Present

Director
JAN 2018 – AUG 2019

Senior Manager
JUL 2016 – DEC 2017

Manager
JUL 2015 – JUN 2016

Strategen Consulting – Berkeley, CA

Independent Consultant
NOV 2012 – JUL 2015

Schlegel & Associates – Phoenix, AZ

JUN 2012 – JUL 2015

Kris Mayes Law Firm – Phoenix, AZ

Project Manager & Researcher
JUN 2012 – JUL 2015

Arizona State University – Tempe, AZ

Instructor
JUN 2011 – MAY 2012

Arizona State University School of Sustainability – Tempe, AZ

Research Fellow
JUL 2007 – JUL 2009

Environmental Defense Fund – New York, NY

EDUCATION

PSM, Solar Energy Engineering and Commercialization
Arizona State University, 2012

MS, Sustainability
Arizona State University, 2011

BA, Chemistry
Princeton University, 2007

EXPERIENCE – 11 YEARS

Energy Resource Planning & Procurement

Utility Rates and Regulation

Cost Benefit Analysis

Avoided Cost and Cost Effectiveness

Energy Policy & Markets

Energy Product Development & Market Strategy

Stakeholder Engagement

Management Consulting

Selection of Relevant Projects at Strategen Consulting

Massachusetts Attorney General's Office

- 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.
- 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 the Consumer Advocate

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

District of Columbia, Office of the People's Counsel

- Provided technical support and analysis on a utility proposed electric vehicle charging program
- Supported drafting comments on the Counsel's position in favor of a more customer-friendly approach to electric vehicle program implementation

North Carolina, Office of the Attorney General

- 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.

Maryland, Office of People's Counsel

- Provided technical support to the state's consumer advocate topics associated with the large PC44 grid modernization effort.
- Topics included electric vehicles, energy storage, distribution grid planning, and interconnection.

Arizona, Residential Utility Consumer Office (RUCO)

- 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.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Portland General Electric

- 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 potential storage technology solution providers.

Xcel Energy

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

City and County of San Francisco

- Aided in evaluation of solar PV with battery storage as a solution for resilience of critical infrastructure.
- Provided technical economic assessment of opportunities for wholesale market participation as an added value for facilities installed.

University of California, San Diego

- Conducted economic analysis to help guide a multi-year research project on the use of advanced solar forecasting technology to improve integrated solar and energy storage.

University of Minnesota

- 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.

Arizona State University (ASU)/Arizona Department of Environmental Quality (ADEQ)

- Project manager for partnership between ASU/ADEQ to study compliance options for the state of Arizona to meet requirements of the EPA's Clean Power Plan (CPP).
- Completed a comprehensive study on the impact of CPP scenarios on the operation of the southwest power grid and cost to Arizona and Navajo Nation electricity customers.

Recent Publications

Edward Burgess, Ellen Zuckerman, and Jeff Schlegel, "Is the Duck Curve Eroding the Value of Energy Efficiency" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2018 Summer Study on Energy Efficiency in Buildings, (pending).

Lon Huber, Ed Burgess, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," (November 2016), Arizona Residential Utility Consumer Office, Arizona Corporation Commission, Docket No. E-00000Q-16-0289, https://www.strategen.com/s/Evolving-the-RPS-Whitepaper.pdf

Mark Higgins, Ed Burgess, and Bill Ehrlich, "Energy Storage Likely to Increase in Utility Resource Planning" Natural Gas and Electricity, Volume 32, Number 10 (May 2016).

Ellen Zuckerman, Edward Burgess, and Jeff Schlegel, "Are Recent Forays into Restructuring a Threat to Energy Efficiency?" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2014 Summer Study on Energy Efficiency in Buildings, (August 2014) http://aceee.org/files/proceedings/2014/data/papers/6-1135.pdf#page=1.

Sonia Aggarwal and Edward Burgess, "Performance Based Models to Address Regulatory Challenges" The Electricity Journal (July 2014) http://www.sciencedirect.com/science/article/pii/S1040619014001389.

"Transmission and Renewable Energy Planning in California," prepared for the Western Governors Association, (November 2012) http://www.westgov.org/wieb/wrez/11-28-2012WREZca.pdf.

Edward Burgess and Petra Todorovich, "High-Speed Rail and Reducing Oil Dependence" in Transport Beyond Oil, Island Press (March 2013).

"On the nature of the dirty ice at the bottom of the GISP2 ice core," Earth & Planetary Science Letters (October 2010). http://www.sciencedirect.com/science/article/pii/S0012821X10006084

Selected Speaking Engagements

- California Energy Storage Alliance, Market Development Forum (February 2019)
- Rutgers University, Rutgers Energy Institute 2018 Annual Symposium (May 2018)
- Energy Storage North America (August 2017)
- MN Energy Storage Workshop (Sept 2016 & Jan 2017);
- Arizona Corporation Commission Peak Demand Workshop, (August 2016);
- Arizona Department of Environmental Quality, Clean Power Plan Technical Working Group, (May 2016);
- Energy Storage North America (2015);
- ASU Clean Power Workshop (February 2015);
- Western Interstate Energy Board Meeting (March 2014).

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/102

REDACTED

Exhibit Accompanying the Opening Testimony of Ed Burgess

Opening Testimony of Ed Burgess in UE 375 (excerpt)

Case: UE 375
Exhibit Number: Sierra Club/100
Witness: Ed Burgess

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Transition Adjustment Mechanism	Docket UE 375

Opening Testimony of Ed Burgess

On Behalf of
Sierra Club

Public Version

May 15, 2020

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optimizes the dispatch of the "company's existing system in the most economic manner while accounting for system constraints."[8]

C. Cost of Coal Fuel Included in the 2021 TAM

Q. Can you provide a breakdown of the coal fuel burn expenses that are included in the 2021 NPC Projections?

A. Yes. As reflected in Workpaper ORTAM21 NPC CONF, the anticipated 2021 coal fuel burn expenses can be broken down by plant as follows:

Table 2: Unit Average Cost based on 2021 projected NPC and generation[9]

Plant	2021 Projected Coal Burn Expenses ($)[10]	2021 Projected Generation (MWh)	Average Cost ($/MWh)
Colstrip	$16,438,683	[redacted]	[redacted]
Craig	$17,499,897	[redacted]	[redacted]
Dave Johnston	$48,459,229	[redacted]	[redacted]
Hayden	$14,769,365	[redacted]	[redacted]
Hunter	$108,641,852	[redacted]	[redacted]
Huntington	$94,054,145	[redacted]	[redacted]
Jim Bridger	$205,967,584	[redacted]	[redacted]
Naughton	$78,436,167	[redacted]	[redacted]
Wyodak	$28,470,445	[redacted]	[redacted]
Total Coal	$612,737,366	[redacted]	[redacted]

Q. How do the TAM 2020 coal generation and fuel expenses compare to TAM 2021?

A. In TAM 2021, coal generation was reduced by [redacted], while coal expenses fell only by 11%,[11] due to higher coal prices. Despite higher coal prices, total NPC over net system

[8] PacifiCorp Response to Sierra Club Data Request 1.4(a). All public discovery responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/105.
[9] 2021 projected generation and average cost do not include operations at the Cholla plant. PacifiCorp owns Cholla Unit 4, and has announced plans to retire this unit by the end of 2020.
[10] PAC/102 at Webb/5.
[11] PAC/300 at Ralston/5:4-Ralston/6:1.

load fell by 4%[12] due to the displacement of coal generation by significantly lower cost renewable resources.[13] Still, after reviewing TAM 2021, it is my conclusion that coal generation remains inefficiently high resulting in unnecessary costs for ratepayers.

Q. Please summarize your observations around the coal units' fuel costs.

A. There is a significant range in coal fuel burn related costs projected for 2021 which PacifiCorp intends to recover, in part, through the TAM. On average, the NPC for all of PacifiCorp's coal plants is expected to be [redacted]; however, for some plants the cost is much higher. For example, the Jim Bridger and Naughton plants have projected coal fuel burn expenses of [redacted] and [redacted], respectively. This is not only significantly higher than other coal units, it is also higher than the average 2021 NPC costs for all generation sources, which is [redacted].

Q. Please explain why it is problematic that these specific units have high fuel costs?

A. There are two reasons for concern. First, lower cost resources are readily available that could be used in their place. Second, not only do these units have high fuel costs but they also have high capacity factors compared to other coal units, which is counterintuitive and illustrates that they are being operated uneconomically and in a manner that is not in the best interests of PacifiCorp ratepayers. I explain both below.

[12] PAC/100 at Webb/7, Figure 1.
[13] TAM 2021 based on the confidential workpaper to the Direct Testimony David Webb on Behalf of PacifiCorp, "ORTAM21 NPC CONF.xlsm,tab NPC [hereinafter "ORTAM21 NPC CONF (Webb)"].
TAM 2020 based on the confidential work paper to the Direct Testimony of David Webb on Behalf of PacifiCorp, "ORTAM21 Testimony Support CONF.xlsx", tab ORTAM20 [hereinafter "ORTAM21 Testimony Support CONF (Webb)"].

PUBLIC UTILITY COMMISSION
OF OREGON

UE 400

EXHIBIT SIERRA CLUB/103

REDACTED

Exhibit Accompanying the Opening Testimony of Ed Burgess

Opening Testimony of Ed Burgess in UE 390 (excerpt)

Docket No. UE 390
Exhibit SC/100
Witness: Ed Burgess

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2022 Transition Adjustment Mechanism	Docket UE 390

Opening Testimony of Ed Burgess

On Behalf of
Sierra Club

Redacted Version

June 9, 2021

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C. <u>Cost of Coal Fuel Included in the 2022 TAM</u>

Q. Can you provide a breakdown of the coal fuel burn expenses that are included in the 2022 NPC Projections?

A. Yes. As reflected in workpaper ORTAM22 NPC CONF, the anticipated 2022 coal fuel burn expenses can be broken down by plant as follows:

Confidential Table 2: Unit Average Cost based on 2022 projected NPC and generation

Plant	2022 Projected Coal Burn Expenses ($)[6]	2022 Projected Generation (MWh)[7]	Average Cost ($/MWh)[8]
Cholla	$ -	-	$ -
Colstrip	14,529,149	[redacted]	[redacted]
Craig	19,084,507	[redacted]	[redacted]
Dave Johnston	61,444,601	[redacted]	[redacted]
Hayden	11,378,872	[redacted]	[redacted]
Hunter	103,544,708	[redacted]	[redacted]
Huntington	99,945,126	[redacted]	[redacted]
Jim Bridger	185,570,462	[redacted]	[redacted]
Naughton	24,416,678	[redacted]	[redacted]
Wyodak	23,501,147	[redacted]	[redacted]
Total	$ 543,415,251	[redacted]	[redacted]

Q. How does the coal fuel burn expense projected in the 2022 TAM differ from the 2021 TAM projection?

A. PacifiCorp's projected coal fuel expense is $114 million lower, or over 17 percent less, than the 2021 TAM forecast because of the lower coal generation volume at PacifiCorp's coal plants.[9]

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[6] PAC/102 at Webb/5.
[7] Confidential workpaper accompanying the Direct Testimony of David Webb (PAC/100) "ORTAM22 NPC CONF.xlsm" at "NPC" tab [hereinafter ORTAM22 NPC CONF (Webb)].
[8] *Id.*
[9] PAC/100 at Webb/20:18-19.

Q. What are the drivers of this substantial decrease?

A. According to PacifiCorp, this is largely due to the Company's continual efforts to update its fueling strategy. As Mr. Ralston states: "[t]his is due to PacifiCorp's continued efforts to work with its coal suppliers and mines for the benefit of our customers."[10]

Q. Do you agree with this?

A. Not entirely. For example, I would agree that the Company is projecting a substantial reduction in coal burn associated with the Naughton plant, which has historically had one of the most expensive fuel sources in PacifiCorp's fleet. However, no coal supply agreement for Naughton is currently in effect for 2022, so it remains to be seen if PacifiCorp's efforts will be successful in reducing these costs by a commensurate level. Additionally, while there was also meaningful reduction in the relatively expensive cost of coal fuel at the Jim Bridger plant, it is not apparent that all steps were taken to reduce these costs. I will explore this more fully in Section 6 of my testimony. Finally, I believe that another major reason for the reduction is not necessarily PacifiCorp's fueling strategy, but rather the fact that PacifiCorp removed the "must run" constraint from the GRID model. When operating as "must run," GRID assumes that PacifiCorp's coal plants operate year around at a specific minimum operating capacity. The removal of this constraint was required as part of the TAM 2021 settlement and is discussed further below. In other words, ratepayers will benefit because the Company was asked to forecast a more economic method for dispatching its coal fleet, rather than assuming that coal units should operate irrespective of their cost—a practice that PacifiCorp was following in previous years.

[10] PAC/200 at Ralston/23:13-14.

Q. What do you conclude from comparing coal unit average costs?

A. Across PacifiCorp's coal fleet, there is a significant range in coal fuel related costs projected for 2022. 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 Naughton plants have projected coal fuel burn expenses of $[redacted]/MWh and $[redacted]/MWh, respectively.

Q. Do these costs, recovered through the TAM, include all of the anticipated costs to PacifiCorp customers for obtaining coal fuel?

A. No. For PacifiCorp's affiliate mines, some of the ongoing costs are recovered as capital expenditures in rate base. For example, PacifiCorp's share of Bridger Coal Company ("BCC") is included in the Company's rate base while other costs including mining costs, depreciation and depletion, and other operating costs are including in NPC and recovered through the TAM. According to the Company, this is a "cost-based approach, limiting the price of Bridger Coal Company coal in rates to operating expenses, plus PacifiCorp's authorized rate of return on the investment in the mine."[11] In reality, coal from BCC has the [redacted] in TAM out of all of the Company's coal fuel sources and as mentioned earlier this does not even include additional costs (e.g. operations & maintenance, fixed costs in rate base) that make the economics of continuing to operate BCC even worse. Regardless of its economic competitiveness, the Company has an incentive to keep operating the mine and plant because it continues to earn a rate of return on the underlying assets and any future capital improvements to them.

[11] The Redacted Comparison Report related to "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" at 4 (provided as an attachment to the PacifiCorp Response to Sierra Club Data Request 1.31) (attached as Exhibit Sierra Club/102).

Docket No. UE 400
Exhibit Sierra Club/104
Witness: Ed Burgess

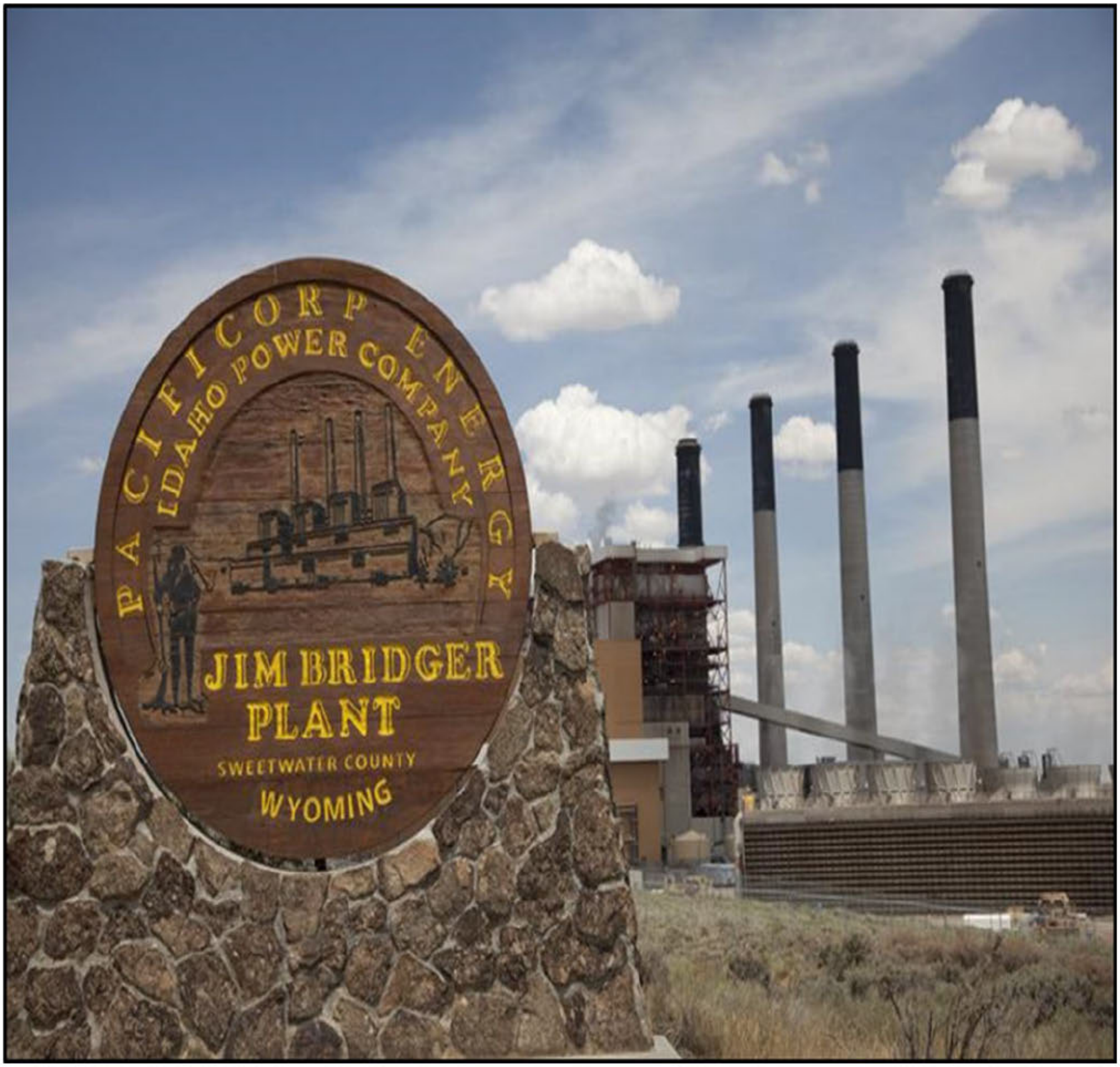
PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/104

Exhibit Accompanying the Opening Testimony of Ed Burgess

Redacted PacifiCorp Long-Term Fuel Supply Plan for the Jim Bridger Plant (Attach Sierra Club 4.2)



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

April 15, 2022

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

HIGHLY CONFIDENTIAL

HIGHLY CONFIDENTIAL

HIGHLY CONFIDENTIAL

1 INTRODUCTION AND EXECUTIVE SUMMARY

In the final order in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, Order No. 13-387, 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. 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 supply 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 refreshed the 2018 Fuel Plan in March 2019. In the final order in PacifiCorp's 2022 TAM, Order No. 21-379, the Oregon Commission required PacifiCorp to update and provide a new long-term fuel plan with the 2023 TAM. In February of 2022, PacifiCorp sought to delay this filing because a number of recent events created significant uncertainty and prevented the Company from definitively determining the least-cost, risk-adjusted coal supply for the Jim Bridger plant at this time.[1] Specifically, these events include recent 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, PacifiCorp's recent commitment to evaluate carbon capture, utilization and storage (CCUS) at the Jim Bridger plant. Since that time additional uncertainty has arisen due to EPA's recent proposal to establish new nitrogen oxides emissions budgets under Ozone National Ambient Air Quality Standards (Ozone Transport Rule), requiring emission sources in 25 states, including Utah and Wyoming, to participate in an allowance-based seasonal trading and emission reduction program.

Recognizing the uncertainties cited in PacifiCorp's motion and the associated difficulties, in Order No. 22-065, the Oregon Commission required PacifiCorp to file this long-term fuel plan (2022 Fuel Plan) on April 15, 2022, but clarified the expectation for the 2022 Fuel Plan:

> *This plan does not need to include a finalized management strategy. Rather, it should lay out the various considerations and options available to PacifiCorp, and its current thinking about how to approach fueling the facility, based on the best information that PacifiCorp has available at this time.*[2]

To develop the 2022 Fuel Plan, PacifiCorp studied, reviewed, and evaluated different fueling options for the Jim Bridger plant. The evaluation of these fueling options provides valuable, although preliminary, insight into [redacted] PacifiCorp has committed through deliberations in the 2021 Integrated Resource Plan (IRP) proceeding in Oregon (Docket No. LC 77) to complete a revised long-term fuel plan and include the plan details as assumptions with the 2023 IRP. Therefore, the alternatives in the 2022 Fuel Plan, as updated and revised, will be subsequently evaluated and modeled in IRP sensitivities and analyses. As part of its 2023 IRP, PacifiCorp intends to assess the 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.

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[1] *In the Matter of the Application 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).
[2] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 22-065 at 5 (Feb. 28, 2022) (Emphasis Added).

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Within the 2022 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 2022 Fuel Plan provides third-party coal supply volume and pricing estimates based upon ongoing discussions with the Black Butte mine, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2022 Fuel Plan provides estimated volumes and rail rates for transportation services based on prior 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 five primary Jim Bridger plant coal fueling options:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [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 PacifiCorp's Net Power Cost (NPC) resulting from the various fueling options, including a composite ranking considering both financial and risk weighting. This analysis is based on the Company's forward price curve for power and natural gas, which does not include greenhouse gas costs, and does not account for the impacts of recently proposed EPA emissions requirements, such as the Ozone Transport Rule. The results of the PVRR analysis and risk evaluation indicate that Scenario 5 is the current least-cost, risk-adjusted option.

The benefits of pursuing Scenario 5 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]

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- [redacted]

Although Scenario 5 is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, recent and ongoing events have increased uncertainty around the future of Jim Bridger's fuel plan such that definitive Jim Bridger long-term coal supply commitments would be inappropriate prior to additional analysis being performed. 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 as necessary to reflect changing assumptions and expectations.

2 EVALUATION METHODOLOGY

In the 2022 Fuel Plan, PacifiCorp evaluated several different fueling options for the Jim Bridger plant. The methodology used to evaluate the fueling options differs from the methodology used in prior long-term fuel plans. When developing prior plans, the Jim Bridger plant generation forecast was derived from PacifiCorp's Generation and Regulation Initiative Decision Tools model (GRID) model and costs for the consumed tons required to support the generation forecast under each fueling option were then calculated. The cost to fuel only the Jim Bridger plant under each fueling option was then compared on a PVRR basis.

The prior long-term fuel plans assumed that the Jim Bridger plant's generation forecast was the same for all evaluated fueling options. The prior plans did not consider the impact that each fueling option's unique cost profile and volume constraints would have on PacifiCorp's overall NPC.

In contrast, the 2022 Fuel Plan evaluation is more holistic and comprehensive. The plan evaluates each fueling option in terms of its impact on PacifiCorp's NPC. Each fueling option's unique cost profile is used in the GRID model to derive the generation forecast for all of PacifiCorp's generating plants. The evaluation further considers the impact of each fueling option on power purchases, wholesale sales and other components of NPC. The total NPC for each fueling option is then compared 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 2019-2021 period, the Jim Bridger plant consumed approximately 18 million tons of coal. PacifiCorp forecasts the plant will consume coal at roughly the same rate, six million tons per year, again in 2022. 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.

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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 NPC.

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:

- PacifiCorp's/Idaho Power's Bridger mine
- The nearby 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 2022 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", "mid-term", and "long-term" periods for discussion purposes. For purposes of the 2022 Fuel Plan, the near-term period has been defined as the next two years (2022-2023) 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 2022 Fuel Plan are explained below:

4.1.1 Generation

As mentioned above, generation forecast assumptions are provided by PacifiCorp's GRID model for each fueling option studied. Consistent with the findings of the 2021 IRP, the 2022 Fuel Plan assumes Jim Bridger Units 1 and 2 will stop consuming coal December 31, 2023, and convert to natural gas in 2024, and Jim Bridger Units 3 and 4 will continue to consume coal until December 31, 2037.

On a total plant basis (i.e., including Idaho Power's expected consumption), coal consumption is forecast to remain in the range of [redacted]llion to [redacted]ion tons per year for 2022 and 2023. Consistent with the 2021 IRP, coal consumption is expected to decline until it ceases in 2037.

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4.1.2 Plant Depreciable Life

The assumed depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2023 for Unit 1 and 2025 for Units 2, 3, and 4 in Oregon. 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.

4.1.1 Bridger Mine Plans

In late 2021, the Bridger mine prepared three operating mine plans with varying coal production volumes through 2028; [redacted]

The four Bridger mine plans are summarized as follows:

- Bridger Mine [redacted]
  - Surface coal production closed in [redacted]
  - Total tons delivered – [redacted]
    - Surface mine – [redacted]
    - Highwall mining – [redacted]
    - Underground mine stockpile – [redacted]
  - Final reclamation earthwork finished in [redacted] (excludes required 10-year monitoring)

- Bridger Mine [redacted]
  - Surface coal production closed in [redacted]
  - Total tons delivered – [redacted]
    - Surface mine – [redacted]
    - Highwall mining – [redacted]
    - Underground mine stockpile – [redacted]
  - Final reclamation earthwork finished in [redacted] (excludes required 10-year monitoring)

- Bridger Mine [redacted]
  - Surface coal production closed in [redacted]
  - Total tons delivered – [redacted]
    - Surface mine – [redacted]
    - Highwall mining – [redacted]
    - Underground mine stockpile – [redacted]
  - Final reclamation earthwork finished in [redacted] (excludes required 10-year monitoring)

- Bridger Mine [redacted]
  - Surface coal production closed in [redacted]
  - Total tons delivered – [redacted]
    - Surface mine/Highwall Mining – [redacted]
    - Underground mine stockpile – [redacted]
  - Final reclamation earthwork finished in [redacted] (excludes required 10-year monitoring)

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4.1.2 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, 20 miles southeast of the Jim Bridger plant, is jointly owned by Lighthouse Resources Inc. (Lighthouse) and Occidental Petroleum. Lighthouse, the operator of the mine, 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] million tons per year and the Jim Bridger plant has been the mine's primary customer. Over the 2019 to 2021 period, the Jim Bridger plant received approximately [redacted] million tons, an average of [redacted] million tons per year, from the Black Butte mine. Based on the current 2022 generation forecast and due to continued high natural gas prices, the Jim Bridger plant is expected to require from [redacted] million to [redacted] million tons of Black Butte coal in 2022. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with UPR.[3]

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 qualitycharacteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In2021, there were seven mining companies operating twelve active mines in Wyoming's Powder River Basin, producing roughly 230 million tons. SPRB mines contain the highest heat content coal 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 would require UPR delivery.

4.1.3 Black Butte Pricing

As of the date of this report, Black Butte mine coal consumed at the Jim Bridger plant is purchased under a Coal Supply Agreement (CSA) signed February 28, 2018. The four-year CSA will expire April 30, 2022. PacifiCorp is negotiating with Black Butte mine for future coal supply. As a policy, and a matter of commercial necessity, PacifiCorp cannot disclose the details or status of these confidential negotiations; however, the Black Butte volumes and pricing used in the 2022 Fuel Plan can be regarded as PacifiCorp's current best estimate of details which can be reasonably assumed for an anticipated CSA (Black Butte CSA).[4]

[redacted]

[3] Due to limited coal reserves, 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.
[4] Once executed, it is expected that the Black Butte CSA will be subject to review in the 2023 TAM proceeding.

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[redacted]

[redacted]

PacifiCorp is holding concurrent negotiations with UPR for coal transportation from the Black Butte mine. [redacted]

4.1.4 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.

For assumed Black Butte mine production in the 2022 Fuel Plan, PacifiCorp has updated these reserve estimates. The estimated reserves have been [redacted] since the date of the 2015 reserve review and have [redacted] based on discussions with Lighthouse [redacted] In addition, the updated reserve estimate takes into consideration Black Butte mine's estimate of mine reserves as of December 2021. As of that date, Black Butte mine claimed permitted reserves of [redacted] tons. As a result, the following production volumes of Black Butte mine coal are assumed in fueling options of the 2022 Fuel Plan that consider the continued purchase of Black Butte mine coal (including estimated Idaho Power purchases) in the long-term:

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

4.1.5 Assumed SPRB Coal Pricing

Due to the Jim Bridger plant's distance from the SPRB, roughly 550 miles by rail, the Jim Bridger plant would source SPRB coal from the mines with the highest heat content (Btu/lb.). The economics of the purchase decision would target coal originating from three mines in the SPRB, Navajo Transitional Energy Company's Antelope mine, Peabody COALSALES, LLC's North Antelope Rochelle Mine and Arch Coal

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Sales Company Inc.'s Black Thunder mine. These mines typically sell coal on an 8,800 Btu/lb. basis as opposed to other areas of the Powder River Basin that sell 8,400 Btu/lb. or lesser heat content coals.

The Powder River Basin is the largest coal mining region in the United States. As a result, standard 8,800 Btu/lb. and 8,400 Btu/lb. Powder River Basin coal is routinely traded, indexed, and forecast. Assumed SPRB coal pricing used in the 2022 Fuel Plan is based on a long-term coal forecast published by EVA in fall 2021.

4.1.6 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, plant management believes that up to a total of 800,000 tons of SPRB coal per year might be safely and reliably consumed without major modifications to the plant. This estimate is considered aggressive, as issues with scheduling or handling coal could result in lower maximum annual SPRB volumes using the existing infrastructure.

4.1.7 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 estimated transportation rates for delivery of Black Butte coal are PacifiCorp's current rail transportation agreement rates adjusted for inflation.

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. 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.

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

In the 2022 Fuel Plan, the capital modifications for Scenario 2 [redacted] The adjusted 2017 capital estimate is then escalated to current dollars. The 2022 Fuel Plan assumes that Idaho Power, with plans to exit the Jim Bridger plant entirely by 2028, will not participate in the capital modifications. Thus, PacifiCorp will incur 100% of the cost. The estimated cost of the capital modifications based on B&M's June 2017 study, approximately [redacted] is provided in Table 1.

[5] PacifiCorp also engaged RungePincockMinarco to evaluate the impact from converting to SPRB coal on the Jim Bridger plant's stockpile level and configuration. This study was used to verify the findings of the Burns & McDonnell study.

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TABLE 1

[redacted]

5 FUEL SUPPLY MIX OF FUELING SCENARIOS

PacifiCorp evaluated five primary fueling scenarios for the Jim Bridger plant for the 2022 Fuel Plan. Those scenarios are described below. Please refer to Appendices 1-18 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, mid-term, and long-term, for each fueling option evaluated are provided below.

5.1 Scenario 1 [redacted]

[redacted]

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[redacted]

- Near-term deliveries (2022-2023)

  [redacted]

- Mid-term deliveries (2024-2028)

  [redacted]

- Long-Term deliveries (2029-2037)

  [redacted]

5.2 Scenario 2 [redacted]

Scenario 2 considers [redacted]

- Near-term deliveries (2022-2023)

  [redacted]

- Mid-term deliveries (2024-2028)

  [redacted]

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[redacted]

- Long-Term deliveries (2029-2037)

[redacted]

5.3 SCENARIO 3 [redacted]

[redacted]

- Near-term deliveries (2022-2023)

[redacted]

- Mid-term deliveries (2024-2028)

[redacted]

- Long-Term deliveries (2029-2037)

[redacted]

5.4 SCENARIO 4 [redacted]

[redacted]

- Near-term deliveries (2022-2023)

[redacted]

- Mid-term deliveries (2024-2028)

[redacted]

- Long-Term deliveries (2029-2037)

[redacted]

5.5 Scenario 5 [redacted]

[redacted]

- Near-term deliveries (2022-2023)

[redacted]

- Mid-term deliveries (2024-2028)

[redacted]

- Long-Term deliveries (2029-2037)

[redacted]

6 PVRR ANALYSIS AND RESULTS

6.1 COST ANALYSIS USING CURRENT JIM BRIDGER PLANT LIFE (DECEMBER 2037)

The PVRR analysis represents a present value revenue requirement analysis of the total NPC for the entire PacifiCorp system. The fuel costs for all coal, gas, and other plants are included along with the wheeling and purchased power costs, net of wholesale power sales revenue. Scenario 2 [redacted] The PVRR results have been discounted using PacifiCorp's weighted average cost of capital. A total dollar PVRR variance or differential has been calculated for each of the five fueling scenarios comparing the total PVRR dollars for each option against Scenario 5, the fueling option with the lowest PVRR dollar amount. As noted above, this does not include analysis for other alternatives for operations at Jim Bridger plant.

Table 2 below shows the results of the PVRR analysis for each fueling option in the 2022 Fuel Plan using the current Jim Bridger plant operational life of December 2037. Also included in Table 2 is a financial ranking from 1 to 5 for each of the five fueling options. The table shows [redacted] The other fueling options fall between these two options. Additional discussion on risk assessment for each fueling option is presented further below.

TABLE 2
PVRR Analysis Through December 2037

[redacted]

6.2 COST ANALYSIS USING OREGON SB 1547 COMPLIANCE DATE (DECEMBER 2029)

After the Company filed the 2018 Fuel Plan, in Order No. 18-421, the Oregon Commission directed PacifiCorp to develop an alternative analysis to evaluate the reasonableness of the Company's fueling strategy for the Jim Bridger plant based upon a shortened plant life of January 1, 2030, instead of 2037. The alternative analysis using the shortened plant life represented a sensitivity analysis and evaluation which would satisfy compliance with Oregon Senate Bill (SB) 1547 signed in 2016. PacifiCorp filed the alternative analysis in March 2019, and it substantiated the results of the original 2018 Fuel Plan.

PacifiCorp has again performed a similar alternative analysis using NPC results through 2029 consistent with Oregon SB 1547. This alternative analysis does not align with PacifiCorp's 2021 IRP preferred portfolio. The depreciation associated with any new plant capital has been accelerated to account for the shortened plant life and all NPC cease at the end of 2029. PVRR results from this compliance view are presented in Table 3 below.

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TABLE 3
PVRR Analysis Through December 2029

[redacted]

[redacted]

6.3 Risk Analysis

The following tables provide a risk assessment for each scenario and outlines the specific categories that have been considered in the risk evaluation analysis. Table 4 illustrates a risk assessment of Scenarios 1 through 5 through the operational life of Jim Bridger plant in December 2037. Table 5 shows a risk summary evaluation through December 2029.

TABLE 4
Risk Evaluation Through 2037

[redacted]

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TABLE 5
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 escalation, (3) Power Market Volatility – risks associated with power market price volatility driven by changing natural gas prices, availability of hydro generation, the impacts of renewable energy sources impacting dispatch, 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 1, 2, or 3 has been assigned. Number 1 is designated as "most favorable and low risk." Number 2 is "less favorable and moderate risk," and number 3 is "least favorable and high risk." The summation of the assigned risk number for each category for each fueling option, results in an overall "composite project risk" score.

[redacted]

The [redacted]

All five scenarios are considered to have similar "Power Market Volatility" exposure and therefore have the same risk ratings. Unexpected changes in prices or availability are driven by changes in natural gas pricing, the availability of hydro generation and overall market demand driven by the broader economy and geopolitical events.

Additionally, all five scenarios are considered to have similar "Jim Bridger Plant Environmental Compliance" exposure and therefore have the same risk ratings.

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As shown in Table 4, the [redacted] are considered to have the same composite risk score of 6 and represent the lowest composite risk rating of the options evaluated. Bridger Mine is located adjacent to the Jim Bridger plant and delivers coal via a conveyor belt. The [redacted] has a composite risk score of 7, slightly higher than the [redacted] and is due to the mine's ownership structure and location requiring rail delivery. The [redacted] has the highest composite risk score of [redacted] driven by the Jim Bridger plant incremental capital investment and coal market risk.

7 AVERAGE COST DISPATCH ANALYSIS

In the final order in PacifiCorp's 2022 TAM, Order No. 21-379, the Oregon Commission stated, "we find that it seems reasonable for PacifiCorp to at least be informed by an average cost analysis that may present a different view than the traditional TAM modeling."[6] To comply with this request, the 2022 Fuel Plan considers a scenario that uses an average cost to dispatch the Jim Bridger plant instead of an incremental cost. Scenario 6 [redacted] to dispatch the Jim Bridger plant.

TABLE 6
PVRR Analysis Through December 2037

[redacted]

As shown in Table 6, the average cost dispatch scenario is the [redacted] most expensive fueling option with a PVRR that is [redacted] more costly than [redacted] The average coal cost used for dispatch at Jim

Bridger plant in Scenario 6 is higher than the incremental cost of Bridger mine production used in [redacted]. As a result of this higher dispatch cost, Jim Bridger coal generation is reduced in some periods and is replaced by more expensive coal and gas generation and power market transactions that were not economic relative to Jim Bridger's incremental cost. Because the savings in Jim Bridger incremental costs for the replaced generation is less than the average coal cost used for dispatch, [redacted]

[6] Order No. 21-379 at 14.

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TABLE 7
PVRR Analysis Through December 2029

[redacted]

As shown above in Table 7, the average cost dispatch scenario is [redacted] when evaluated through 2029.

By allowing the Jim Bridger plant to dispatch consistent with the prices and quantities under each supply option, the 2022 Fuel Plan captures the benefits of flexibility and maximizes the benefits of the supply available in each year under each scenario. This allows each scenario to reflect different optimal quantities. While fixed costs are a key component of the long-term coal supply analysis in the 2022 Fuel Plan, their inclusion in the average cost used for dispatch does little to identify which options are least-cost, risk-adjusted. Fixed costs are likely to be a key feature of any alternatives to current coal-fired operations at Jim Bridger Units 3 and 4, including retrofit for CCUS, conversion to natural gas and/or other alternative fuels, and early retirement (i.e., replacement by other resource alternatives). The flexibility to change generation output and increase or decrease variable costs in response to changing requirements is a key part of portfolio selection and cost and risk analysis performed in the IRP.

This result is intuitive, because with past investment in Bridger mine ownership, PacifiCorp's customers have purchased the option to benefit from (i) low-cost Bridger mine incremental production as needed and (ii) the operational flexibility to prudently increase or decrease production as needed within reasonable operating limits. By arbitrarily dispatching Bridger plant on an average rather than incremental basis, the customer is denied the benefit of Bridger mine's low-cost incremental production. In this case, the cost of the foregone benefit is roughly [redacted] over the life of the plant. Incremental energy purchased at higher market pricing will also require a fixed commitment. With mine ownership, customers have the benefit of being able to both increase and decrease production volumes, without the fixed commitments that come from commercial arrangements with third parties. The added cost resulting from a comparison of Scenario 6 to [redacted], clearly demonstrates the value the customer loses from choosing to dispatch a plant on an average, rather than an incremental, cost basis.

8 REMAINING UNCERTAINTIES

As mentioned above, 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 impossible at this time. The following is a short summary of some of the major uncertainties

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that impact the 2022 Fuel Plan and an explanation of how the plan may change depending on the resolution of the uncertainties.

8.1 Jim Bridger Units 1 and 2 Gas Conversions

Jim Bridger Units 1 and 2 are scheduled to be converted to natural gas in 2024 based on the Company's 2021 IRP analysis, which indicated that a portfolio without these units being converted to natural gas would result in higher costs to PacifiCorp customers.[7] The natural gas conversion of these units is also an enforceable environmental compliance requirement under a consent decree entered into by the state of Wyoming and the Company. [8] The consent decree was entered into pursuant to state regional haze requirements under the Clean Air Act (CAA) and has been submitted to the EPA for review. PacifiCorp has also submitted to Wyoming and EPA air permit modifications and proposed revisions to regional haze state implementation plans which include the gas conversion of Units 1 and 2. To date, EPA has not finalized its review of the consent decree and neither Wyoming nor EPA has completed review of the proposed permit modifications and state plan revisions. These factors create uncertainty of potential changes to environmental compliance requirements as there has been no final outcome of these complicated compliance processes. The conversion to natural gas will change how these units and PacifiCorp's generation fleet are dispatched. As such, there are additional uncertainties on the operational impact to Jim Bridger Units 3 and 4.

Due to these uncertainties, [redacted]

8.2 PacifiCorp's commitment 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 requires the Company to issue request(s) for proposals for the installation of CCUS at Jim Bridger Units 3 and 4 no later than January 1, 2023. 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 increase if PacifiCorp elects to, or is required to, install CCUS at Bridger Units 3 and/or 4. [redacted]

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[7] PacifiCorp's 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results, pages 269-270.
[8] Wyoming Consent Decree, Docket No. 2022-CV-200-333 (February 14, 2022).

HIGHLY CONFIDENTIAL

8.3 PROPOSED EPA RULES

The EPA is proposing Federal Implementation Plan requirements for 26 states, including Wyoming, to eliminate significant contributions to nonattainment of the 2015 ozone National Ambient Air Quality Standard in neighboring states, known as the Ozone Transport Rule, "good neighbor rule," or "interstate transport" provision of the CAA.[9]

Implementation of the Ozone Transport Rule may require selective catalytic reduction (SCR) technology installation for units that do not currently have them. As customers have already incurred the cost of SCR on both Jim Bridger Units 3 and 4, these units may take on an even more critical role in the compliance and reliability strategy for PacifiCorp's fleet and may operate at higher levels than currently forecast. Proceeding with Scenario 5, 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 best course of action for compliance with the proposed rule.

Also, as part of the Ozone Transport Rule, EPA proposed to require fossil fuel-fired power plants in those states to participate in an allowance-based ozone season trading program beginning in 2023. The proposed emissions reductions required under the trading program, if finalized, would impact the Company and its operations. PacifiCorp is still evaluating these impacts.

How this proposed rule will impact PacifiCorp's fleet is unclear at this time. [redacted]

8.4 IDAHO POWER COMPANY'S PLANNED EXIT DATES

PacifiCorp's 2021 IRP Preferred Portfolio calls for Jim Bridger plant Units 1 and 2 to cease consuming coal on December 31, 2023. Units 1 and 2 are expected to convert to natural gas consumption at that time. PacifiCorp's 2021 IRP also provides December 31, 2037, as the closure date for Units 1, 2, 3, and 4. PacifiCorp and Idaho Power Company (Idaho Power) are apparently aligned in the decision to consume coal in Units 1 and 2 through 2023, prior to those units converting to natural gas consumption, as Idaho Power's 2021 IRP calls for the conversion of two units to natural gas consumption in 2024. However, PacifiCorp and Idaho Power differ on the utilization 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.

As co-owners of Jim Bridger plant and Bridger mine, PacifiCorp and Idaho Power will have to determine how to align their plans or unwind their joint ownership while best accommodating 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.

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

HIGHLY CONFIDENTIAL

9 CONCLUSION

In this 2022 Plan, PacifiCorp has identified a preliminary long-term fueling plan for the Jim Bridger plant to align with the Company's 2021 IRP, respond to changing fuel requirements due to market conditions, and allow flexibility to deal with uncertainty. This plan is not a finalized management strategy, but simply lays out the various considerations and options available to PacifiCorp based on the best information available at this time. Hypothetical mine plans have been developed, evaluated, and reviewed for the Bridger mine. The various mine options have provided information and direction in determining the optimal total volume at the Bridger mine. Different mine closure dates for the surface mining operations have been considered and evaluated. Persistently high natural gas pricing and resultant near-term high forecast generation from the Jim Bridger plant have made ongoing discussions necessary with Lighthouse and UPR to develop new near-term coal and transportation agreements for the Black Butte mine. Based on these discussions, PacifiCorp can reasonably estimate new contract rates for Black Butte mine coal and rail transportation services.

After considering factors influencing this long-term fueling strategy and information available to the Company at this time, five 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, Scenario 5 is the current least-cost, risk-adjusted option and informs PacifiCorp's Jim Bridger plant fueling strategy. This preliminary plan would potentially allow PacifiCorp and the plant [redacted]

Although Scenario 5 is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, recent and ongoing events have increased uncertainty around the future of Jim Bridger's fuel plan such that entering into definitive Jim Bridger long-term coal supply commitments would be inappropriate prior to additional analysis being performed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant and will update the long-term fuel supply plan to reflect changing assumptions and expectations with the 2023 IRP.

HIGHLY CONFIDENTIAL

APPENDIX 1 – SCENARIO 1 – [redacted]

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 2 – SCENARIO 2 – [redacted]

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 3 – SCENARIO 3 – [redacted]

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 4 – SCENARIO 4 – [redacted]

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 5 – SCENARIO 5 – [redacted]

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 30 – SCENARIO [redacted]

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 7 – SCENARIO 1 – CONSUMED FUEL SUMMARY

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 7 – SCENARIO 1 – CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 8 – SCENARIO 2 – CONSUMED FUEL SUMMARY

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 8 – SCENARIO 2 – CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 9 – SCENARIO 3 – CONSUMED FUEL SUMMARY

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 9 – SCENARIO 3 – CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 10 – SCENARIO 4 – CONSUMED FUEL SUMMARY

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 10 – SCENARIO 4 – CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 11 – SCENARIO 5 – CONSUMED FUEL SUMMARY

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 11 – SCENARIO 5 – CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 12 – SCENARIO 6 – CONSUMED FUEL SUMMARY

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 12 – SCENARIO 6 – CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 13 – SCENARIO 1 – JIM BRIDGER PLANT

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 13 – SCENARIO 1 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 14 – SCENARIO 2 – JIM BRIDGER PLANT

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 14 – SCENARIO 2 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 15 – SCENARIO 3 – JIM BRIDGER PLANT

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 15 – SCENARIO 3 – JIM BRIDGER PLANT (CONT'D)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 16 – SCENARIO 4 – JIM BRIDGER PLANT

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 16 – SCENARIO 4 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 17 – SCENARIO 5 – JIM BRIDGER PLANT

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 17 – SCENARIO 5 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 18 – SCENARIO 6 – JIM BRIDGER PLANT

[redacted]

HIGHLY CONFIDENTIAL

APPENDIX 18 – SCENARIO 6 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/105

Exhibit Accompanying the Opening Testimony of Ed Burgess

Selected PacifiCorp Public Data Responses

Exhibit Sierra Club/105

Selected PacifiCorp Public Data Responses

1. PacifiCorp Response to Sierra Club Data Request 2.2
2. PacifiCorp Response to Sierra Club Data Request 2.12
3. PacifiCorp Response to Sierra Club Data Request 2.13
4. PacifiCorp Response to Sierra Club Data Request 3.8
5. PacifiCorp Response to Sierra Club Data Request 3.9
6. PacifiCorp Response to Sierra Club Data Request 3.12
7. PacifiCorp Response to Sierra Club Data Request 3.13
8. PacifiCorp Response to Sierra Club Data Request 3.14
9. PacifiCorp Response to Sierra Club Data Request 4.3
10. PacifiCorp Response to Sierra Club Data Request 4.5
11. PacifiCorp Response to Sierra Club Data Request 4.6
12. PacifiCorp Response to Sierra Club Data Request 4.7
13. PacifiCorp Response to Sierra Club Data Request 4.8
14. PacifiCorp Response to Sierra Club Data Request 4.12
15. PacifiCorp Response to Sierra Club Data Request 5.2
16. PacifiCorp Response to Sierra Club Data Request 5.3
17. PacifiCorp Response to Sierra Club Data Request 5.4

UE-400 / PacifiCorp
April 20, 2022
Sierra Club Data Request 2.2

Sierra Club Data Request 2.2

> **CONFIDENTIAL REQUEST – Naughton -** Prior to executing the Naughton CSA, did PacifiCorp perform any dispatch analysis in the GRID model or AURORA model for any of the years [redacted] that included estimated or actual prices and quantities for the new CSA? If so, please provide the results.

Response to Sierra Club Data Request 2.2

> No. The dispatch analysis for the Naughton coal supply agreement (CSA) was performed in the PLEXOS model. Please refer to the Company's response to Sierra Club Data Request 2.1.

UE-400 / PacifiCorp
April 20, 2022
Sierra Club Data Request 2.12

Sierra Club Data Request 2.12

Bridger Coal Company - How much coal can be stored at the BCC mine at one time?

Response to Sierra Club Data Request 2.12

Bridger Coal Company's (BCC) air quality permit has an effective date of April 1, 2022. The new permit has lower fugitive dust emissions than the former permit and was adjusted to reflect changes associated with the underground mine closure. Effective April 1, 2022, BCC's total maximum live stockpiled coal storage is 675,000 tons and the maximum sealed stockpiled coal storage is 1,900,000 tons.

UE-400 / PacifiCorp
April 20, 2022
Sierra Club Data Request 2.13

Sierra Club Data Request 2.13

Bridger Coal Company - How much coal can be stored at the Jim Bridger plant at one time?

Response to Sierra Club Data Request 2.13

Jim Bridger Plant's existing air quality permit limits coal stockpile inventory to a maximum of 1,500,000 tons of coal at any one time, with the total plant annual average tonnage no more than 1,331,000 tons. Note: the plant becomes physically constrained at a volume less than 1,500,000 tons.

UE-400 / PacifiCorp
April 22, 2022
Sierra Club Data Request 3.8

Sierra Club Data Request 3.8

Please refer to PAC/200 at Owen/14:14-15:1, which states: "The mobile equipment fleet was scheduled to operate two shifts per day, four days per week and 10 hours per day in both TAM filings".

(a) Please explain PacifiCorp's use of the past tense "was" in this sentence. More specifically, has PacifiCorp already made commitments to maintain this operating schedule through the remainder of 2022 and 2023?

(b) Please explain what flexibility PacifiCorp has to modify this operating schedule in 2022 and 2023.

(c) Please reconcile this statement with previous statements PacifiCorp representative Brian Greer made in the February 24, 2022 IRP workshop (executive session).

Response to Sierra Club Data Request 3.8

(a) As a prerequisite to filing the 2023 TAM, BCC personnel were required to develop an engineered mine plan and forecast costs for inclusion in the TAM filing. The word "was" noted this process occurred prior to the TAM submittal. Bridger Coal Company (BCC) has the option to amend shift operating schedules in 2022 or 2023.

(b) BCC has the ability to change shift schedules to align coal production and Jim Bridger plant coal delivery requirements within reasonable limits. Per the collective bargaining agreement, BCC must provide at least 30 days' notice and the new schedule must last at least four months in duration prior to changing shift schedules.

(c) To our knowledge, Mr. Greer did not speak about mobile fleet production shifts in the IRP workshop executive session held February 24, 2022.

UE-400 / PacifiCorp
April 22, 2022
Sierra Club Data Request 3.9

Sierra Club Data Request 3.9

CONFIDENTIAL REQUEST - Please refer to PAC/200 at Owen/15:12-16, which states: "Q. Please explain why materials and supplies increased by [redacted]] in the 2023 TAM. A. As discussed above, the equipment fleet moves more cubic yards of material, uncovers more coal and consequently operates more hours in the 2023 TAM than assumed in the 2022 TAM".

(a) Please explain whether the 2023 materials and supplies cost would still increase by [redacted]] if the equipment fleet moved a lower volume of material (e.g. 50% lower).

(b) What would be the increase/decrease in materials and supplies costs from 2022 to 2023 if only [redacted] tons of coal were uncovered from the Bridger mine in 2023?

Response to Sierra Club Data Request 3.9

PacifiCorp objects to this request because it is requesting the Company to speculate on an event that is not currently anticipated to occur, and is not reasonably calculated to lead to admissible evidence in this proceeding. Notwithstanding the foregoing objection, the Company responds as follows:

Operating the mine on a significantly reduced level (e.g. 50% lower) has not been evaluated because forecasted Jim Bridger plant generation levels necessitate a significant quantity from BCC. It is impractical to speculate how materials and supplies expenses would be impacted in a one-year plan.

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April 22, 2022
Sierra Club Data Request 3.12

Sierra Club Data Request 3.12

CONFIDENTIAL REQUEST - Please refer to PAC/200 at Owen/17:1, which states: "Q. Why did base labor costs decrease by [redacted]?"

(a) Please explain whether 2023 labor costs could be further reduced if a substantially lower coal volume was extracted from the BCC mine in 2023 (e.g., on the order of 50% lower than proposed in the 2023 TAM).

Response to Sierra Club Data Request 3.12

PacifiCorp objects to this request because it is requesting the Company to speculate on an event that is not currently anticipated to occur, and is not reasonably calculated to lead to admissible evidence in this proceeding. . Notwithstanding the foregoing objection, the Company responds as follows:

Operating the mine on a significantly reduced level (e.g. 50% lower) was not evaluated because forecasted Jim Bridger plant generation levels necessitate a significant quantity from BCC. It is impractical to speculate how labor expenses would be impacted in a one-year plan.

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April 22, 2022
Sierra Club Data Request 3.13

Sierra Club Data Request 3.13

> **CONFIDENTIAL REQUEST** - Please refer to PAC/200 at Owen/17:9-11 which states: "In summary, the 2023 TAM assumes [[redacted] less tons will be delivered from inventory which will reduce BCC operating costs by [redacted]].

(a) Please explain why so much less coal is being delivered from inventory in the 2023 TAM than the 2022 TAM.

(b) Please specify how much BCC coal (in tons) is expected to be held in inventory in each month for 2022 and 2023.

(c) Please describe the accounting method PacifiCorp uses for determining the cost of coal delivered from inventory in 2022 and 2023.

(d) Please explain whether the projected 2023 coal inventory costs projected by PacifiCorp would be lower if the consumption of coal by the Jim Bridger power plant were also lower than PacifiCorp's 2023 forecast (e.g., 50% lower).

Response to Sierra Club Data Request 3.13

(a) In the 2022 TAM, only one dragline was scheduled to operate on a full-time 4x4 schedule and BCC delivered more coal to the Jim Bridger plant than was produced. In the 2023 TAM, two draglines are scheduled to operate on a full-time 4x4 schedule and BCC is projected to deliver less coal than produced.

(b) Please refer to Attach SC 3.13 CONF. The attachment assumes the question is referring to month-end accounting coal inventory balances assumed in the 2022 TAM and the 2023 TAM.

(c) For accounting purposes, BCC uses an average cost inventory method as shown in the table below:

UE-400 / PacifiCorp
April 22, 2022
Sierra Club Data Request 3.13

[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]	[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]

BCC combines beginning inventory balances (tons/dollars) with tons mined and mining costs. This composite provides the coal inventory available to be shipped from inventory and reflects an average cost for tons in inventory. When tons are shipped, the available tonnage amount is reduced by the shipped tonnage amount and yields the ending inventory balance. The available coal inventory cost is reduced by the average cost of the tons shipped. As identified above in the “Jan. 2023 – Cost Per Ton” table, the cost per ton value is the same for inventory available, shipped and ending inventory values.

(d) PacifiCorp objects to this request because it is requesting the Company to speculate on an event that is not currently anticipated to occur, and is not reasonably calculated to lead to admissible evidence in this proceeding. Notwithstanding the foregoing objection, the Company responds as follows:

Operating the mine on a significantly reduced level (e.g. 50% lower) was not evaluated because forecasted Jim Bridger plant generation levels necessitate a significant quantity of coal from BCC.

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UE-400 / PacifiCorp
April 22, 2022
Sierra Club Data Request 3.14

Sierra Club Data Request 3.14

CONFIDENTIAL REQUEST - Please refer to PAC/200 at Owen/17:14-15, which states: "The 2023 TAM includes [redacted] for underground mine depreciation and [redacted] for surface depreciation".

(a) Please explain whether the projected 2023 surface mine depreciation costs would be lower if the volume of coal extracted in 2023 was also substantially lower (e.g., on the order of 50% lower than proposed in the 2023 TAM).

Response to Sierra Club Data Request 3.14

PacifiCorp objects to this request because it is requesting the Company to speculate on an event that is not currently anticipated to occur, and is not reasonably calculated to lead to admissible evidence in this proceeding. Notwithstanding the foregoing objection, the Company responds as follows:

Operating the mine on a significantly reduced level (e.g. 50% lower) was not evaluated because forecasted Jim Bridger plant generation levels require a significant coal delivery quantity from BCC.

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.

UE-400 / PacifiCorp
May 10, 2022
Sierra Club Data Request 4.3

Sierra Club Data Request 4.3

HIGHLY CONFIDENTIAL REQUEST - With respect to the Jim Bridger Fuel Plan, please:

[redacted]

Response to Sierra Club Data Request 4.3

(a) A dispatch tier and costing tier for coal plants was used in the Generation and Regulation Initiative Decision Tool (GRID) study for the Jim Bridger Plant Long-Term Fuel Supply Plan, consistent with the methodology described in the Company's response to Sierra Club Data Request 1.4 subpart (a) in the Company's 2021 transition adjustment mechanism (TAM), Docket UE-375.

(b) The dispatch tier and costing tier for coal plants in each of the six scenarios is not related to coal suppliers.

(c) The requested information is commercially sensitive and deemed highly confidential. The Company requests special handling. Please refer to the Company's response to Sierra Club Data Request 4.1, specifically Highly Confidential Attachment SC 4.1, which provides the incremental dispatch and total cost pricing and volumes for each of the six scenarios.

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May 10, 2022
Sierra Club Data Request 4.3

(d) The dispatch tier and costing tier were used in GRID.

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May 10, 2022
Sierra Club Data Request 4.5

Sierra Club Data Request 4.5

[redacted]

Response to Sierra Club Data Request 4.5

PacifiCorp's Generation and Regulation Initiative Decision Tool (GRID) model was used for the Jim Bridger Long-Term Fuel Supply Plan analysis, because the AURORA model is not yet configured and maintained to perform longer term model runs beyond a one-year period. This set up could not take place in time to meet the deadline for the analysis to be completed.

UE-400 / PacifiCorp
May 10, 2022
Sierra Club Data Request 4.6

Sierra Club Data Request 4.6

[redacted]

Response to Sierra Club Data Request 4.6

The PLEXOS model is primarily used for planning of future resource development and is the best model to serve long-term demand needs and resource selection. The PLEXOS model as configured by PacifiCorp's Integrated Resource Plan (IRP) group receives less frequent input and configuration updates than the Generation and Regulation Initiative Decision Tool (GRID) used by the Company's finance department. The finance department updates inputs and assumptions in GRID on a monthly basis, and therefore the GRID model was in a better position for meeting the Jim Bridger Long-Term Fuel Supply Plan deadline. GRID, used by the Company's finance department also regularly compares coal generation forecast results to actual results and makes forecast adjustments as are necessary, whereas the PLEXOS model results performed by the Company's IRP group is focused on comparing generation results from one scenario to another, rather than comparing generation forecasts to actual results.

UE-400 / PacifiCorp
May 10, 2022
Sierra Club Data Request 4.7

Sierra Club Data Request 4.7

[redacted]

Response to Sierra Club Data Request 4.7

Coal from the Black Butte mine is required in every scenario to fuel Jim Bridger plant generation as forecast by PacifiCorp's Generation and Regulation Initiative Decision Tool (GRID) model through 2022 and 2023. The Bridger Coal Company (BCC) underground mine shuttered in 2021 which reduced BCC's total production capacity.

UE-400 / PacifiCorp
May 10, 2022
Sierra Club Data Request 4.8

Sierra Club Data Request 4.8

HIGHLY CONFIDENTIAL REQUEST - In the Company's 2021 IRP (Dkt. No. LC 77), PacifiCorp provided the results of a PLEXOS model run that included no take or pay minimums for Jim Bridger ("No Minimum Scenario").

(a) [redacted]

(b) Please provide a comparison of the fuel consumed in each year from Jim Bridger (in both tons and MMBtu) between: [redacted].

(c) [redacted].

Response to Sierra Club Data Request 4.8

(a) The purpose of the long-term fuel supply plan is to determine the least-cost, risk-adjusted coal supply evaluated on a multi-year basis. The long-term fuel supply plan is designed to ensure that fuel supplies are fair, just, and reasonable, and that they satisfy the Public Utility Commission of Oregon's (OPUC) prudence and affiliate interest standards.

The PLEXOS model run that included no take or pay minimums for Jim Bridger ("No Minimum Scenario") was a hypothetical model run undertaken at the request of Oregon stakeholders in PacifiCorp's Integrated Resource Plan (IRP). The "No Minimum Scenario" PLEXOS model run evaluates assumptions that are not necessarily operationally practical or feasible. Therefore, the "No Minimum Scenario" was not considered for the long-term fuel supply plan. The Company is evaluating input updates and modeling improvements for the 2023 IRP with consideration of stakeholder concerns.

(b) For (1), the Jim Bridger Fuel Plan, please refer to the Company's response to Sierra Club Data Request 4.1, specifically Highly Confidential Attachment 4.1. For (2) and (3), please refer to Confidential Attachment Sierra Club 4.8. Note: for the comparison to (2) PacifiCorp's preferred plan in the 2021 IRP, and (3) the no minimum scenario evaluated in the 2021 IRP, the PLEXOS model does not report fuel tons, therefore the requested fuel ton information is not available. GBtu (giga British thermal units) is reported and can be multiplied by 1,000 to report million British thermal units (MMBtu).

(c) Please refer to the Company's response to subpart (a) above. Additionally, the Company's forward price curve (FPC) used in the long-term fuel supply plan includes updated power and natural gas market pricing, while the 2021 IRP evaluated a variety of cost assumptions including greenhouse gas assumptions in future years.

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UE-400 / PacifiCorp
May 10, 2022
Sierra Club Data Request 4.12

Sierra Club Data Request 4.12

HIGHLY CONFIDENTIAL REQUEST - Please refer to page 9 of the Jim Bridger Fuel Plan:

[redacted]

Response to Sierra Club Data Request 4.12

(a) Determination of the least-cost, risk-adjusted fueling option for the Jim Bridger units will be assessed as part of PacifiCorp's 2023 Integrated Resource Plan (IRP). Final determination of any long-term commitments would be made based on model results and any final cost and performance information for the available options.

(b) The Company only has an ability to terminate existing coal supply agreements (CSA) consistent with their terms, therefore, except to the extent termination is allowed under the CSA, the determination of the least-cost, risk-adjusted option is considered prior to execution of any new CSA.

UE-400 / PacifiCorp
May 17, 2022
Sierra Club Data Request 5.2

Sierra Club Data Request 5.2

Please refer to SC 2.9, which states: "Incremental costs between lower coal production and higher coal production plans are calculated. The incremental coal costs are incorporated in the net power costs (NPC) production cost model analyses to forecast plant generation (megawatt-hours (MWh) and million British thermal units (MMBtu) consumed)".

(a) Please specify which plans were used to determine the "lower coal production" and "higher coal production" volumes in the 2023 TAM.

(b) Please specify what PacifiCorp assumed for the "incremental coal costs" for BCC and Jim Bridger in its production cost model analyses for the NPC.

(c) Please clarify whether the incremental costs are linked to the "Incremental Tons Dlvd" shown on line 24 of Attach SC 2.9, or some other value.

Confidential Response to Sierra Club Data Request 5.2

The Company assumes that the reference to "Attach SC 2.9" is intended to be a reference to Confidential Attachment SC 2.9. Based on the foregoing clarification and assumption, the Company responds as follows:

(a) The "lower coal production" plan is the option named "Opt. 3a 2.8 Plan - Nov 4.0 Fcst" and the "higher coal production" plan is the option named "Opt. 1&2H 3.38 Plan - Nov 4.0 Fcst". The incremental volume between these two plans was used to calculate the incremental surface mine price. The underground mine incremental price is a forecast of costs used to deliver stockpiled underground coal.

(b) In this 2023 transition adjustment mechanism (TAM), PacifiCorp used an incremental price of [redacted] per million British thermal units (MMBtu).

(c) Referencing the Company's response to Sierra Club 2.9, incremental costs are associated with values on line 24 of Confidential Attachment SC 2.9.

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.

UE-400 / PacifiCorp
May 17, 2022
Sierra Club Data Request 5.3

Sierra Club Data Request 5.3

Please refer to SC 2.10:

(a) When will the Company finalize the 2023 BCC Mine Plan, and the 2023 10-year business plan?

(b) Please provide the 2022 10-year business plan and 2022 BCC Mine Plan.

(c) Please identify and describe any differences between the 2022 BCC Mine Plan, 2022 Business Plan, and 2022 TAM NPC forecast regarding the volume and cost of BCC coal.

Response to Sierra Club Data Request 5.3

(a) The Company anticipates finalizing the 2023 Bridger Coal Company (BCC) mine plan, and the 2023 10-year business plan in Q4 2022.

(b) PacifiCorp objects to this request as broad, overly burdensome, and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

Please refer to Confidential Attachment SC 5.3 which provides information prepared for Jim Bridger and BCC for years 2022-2023 as part of the 2022 10-year business plan.

(c) Please refer to Confidential Attachment SC 5.3 and the work papers in Docket UE-390, the 2022 transition adjustment mechanism (TAM), to compare differences between 2022 BCC mine plan, the 2022 10-year business plan, and the 2022 TAM net power costs (NPC) forecast.

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.

UE-400 / PacifiCorp
May 17, 2022
Sierra Club Data Request 5.4

Sierra Club Data Request 5.4

CONFIDENTIAL REQUEST - Please refer to Response to SC 3.1(a):

(a) Was the specific Black Butte volume (i.e., [redacted] determined by the AURORA model run used for the 2023 TAM? If not, was a separate AURORA model run used to determine this volume?

(b) If AURORA was not used to determine the [redacted] volume, please provide PacifiCorp's calculations or supporting work papers used to determine this value.

(c) Within PacifiCorp's AURORA model results, please identify the specific location of the generation forecast result (in MWh and MMBtu) that supports the delivery volume of [redacted] from Black Butte, the specific deliveries available from Bridger Coal Company (in tons and MMBtu), and their location in the AURORA model results and/or inputs.

(d) Was the [redacted] estimated price assumption used in performing the 2023 TAM AURORA model runs? If so, please explain in detail how this price was incorporated in the Jim Bridger plant dispatch costs.

(e) Were different combinations of coal volumes from BCC (base tons) and Black Butte modeled in AURORA for the 2023 TAM, or was only a single volume scenario evaluated? Please provide the volume combinations considered.

(f) Did PacifiCorp assume any incremental or supplemental coal would be available from Black Butte in 2023, beyond the [redacted]?

   i. If not, why not?
   ii. If so, what was the supplemental price of this coal?

Confidential Response to Sierra Club Data Request 5.4

(a) The Black Butte volume estimate was developed based upon preliminary discussions with the coal supplier surrounding a potential new coal supply agreement (CSA) to begin in 2022 and through professional judgement. Additionally, the amount was informed by PacifiCorp's share of the prior CSA which was [redacted]

[redacted] The volume estimate was also informed by several iterative AURORA model runs for this 2023 transition adjustment mechanism (TAM) and by the volume of coal deliveries expected to be available from Bridger Coal Company (BCC) during 2023.

(b) Please refer to the Company's response to subpart (a) above.

(c) Please refer to the Company's response to subpart (a) above. The AURORA model produces a generation forecast for each generating plant in PacifiCorp's system based upon incremental prices, plant attributes and other system inputs. The generation (megawatt-hours (MWh)) is associated with volumes of coal consumed (million British thermal units (MMBtu)), not coal delivered. Therefore, any specific delivery amounts of Black Butte or BCC are not contained within the AURORA model.

(d) No, the total delivered price estimate was not used as an input to the 2023 TAM AURORA model runs.

(e) As discussed in the Company's response to subpart (a) above, several preliminary iterations were performed in AURORA to inform the scenario submitted in this 2023 TAM. The results of the final AURORA model run are provided in the net power costs (NPC) report supporting the direct testimony of Company witness, Michael G. Wilding. Specifically, confidential file "ORTAM23 NPC CONF" provided with the Company's responses to TAM Support Set 1 (concurrent).

(f) No, PacifiCorp did not assume any incremental coal from Black Butte in the 2023 TAM as the preliminary discussions from the coal supplier did not suggest substantial supplemental coal at the time of the direct filing.

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 400
Exhibit Sierra Club/106
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/106

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to Western Resource Advocates Data Request 4.28 in Utah Public Service Commission Docket No. 21-035-09

21-035-09 / Rocky Mountain Power
November 17, 2021
WRA Data Request 4.28

WRA Data Request 4.28

In undertaking endogenous coal retirement, was the model allowed to avoid projected take-or-pay coal supply agreements (CSA) by retiring the unit, or were projected CSAs considered a sunk cost?

Response to WRA Data Request 4.28

The PLEXOS model avoided the projected take-or-pay fuel costs when the Jim Bridger plant retired early. In the PLEXOS model, only Jim Bridger was set-up with projected take-or-pay fuel costs.

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/107

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to Western Resource Advocates Data Request 4.2
in Utah Public Service Commission Docket No. 21-035-09

21-035-09 / Rocky Mountain Power
November 17, 2021
WRA Data Request 4.2

WRA Data Request 4.2

For each coal-fired generating plant with a take-or-pay contract:

(a) Identify the expiration date of the current contract.

(b) For any of the coal plants with expiring contracts, does the modeling assume any further take-or-pay contracts are entered into following the expiration of the current contracts? If so, please identify the plants and the contract terms assumed including new expiration dates.

(c) For any coal plants currently fueled through Company-owned mines, were take-or-pay contracts modeled following closure of the mine?

Response to WRA Data Request 4.2

(a) Please refer to Confidential Attachment WRA 4.2. In the cases where a plant has more than one coal supply agreement (CSA), the year provided is for the earliest point when there is at least one projected CSA.

(b) Please refer to the Company's response to WRA Data Request 4.28.

(c) Only the Craig and Jim Bridger plants are fueled through Company-owned mines. A take-or-pay contract was modeled for Jim Bridger following the closure of the mine, but not for the Craig plant.

Confidential information is provided subject to R746-1-601–606 of the Utah Public Service Commission Rules.

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/108

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Highly Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 4.1 “GEN Forecast_2022BP_v2_20220314_Scenario 3”

This exhibit is highly confidential pursuant to Modified Protective Order No. 22-063.

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

Docket No. UE 400
Exhibit Sierra Club/109
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/109

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Highly Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 4.1 “GEN Forecast_2022BP_v2_20220314_Scenario 6”

This exhibit is highly confidential pursuant to Modified Protective Order No. 22-063.

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PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/110

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.15 “Attach SC 2.15-1 CONF”

This exhibit is confidential pursuant to Protective Order No. 16-128.

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EXHIBIT SIERRA CLUB/111

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.8 “Attach SC 2.8-2 CONF”

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OF OREGON

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EXHIBIT SIERRA CLUB/112

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 3.13 “Attach SC 3.13 CONF”

This exhibit is confidential pursuant to Protective Order No. 16-128.

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

Docket No. UE 400
Exhibit Sierra Club/113
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/113

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.9 “Attach SC 2.9 CONF”

This exhibit is confidential pursuant to Protective Order No. 16-128.

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EXHIBIT SIERRA CLUB/114

REDACTED

Exhibit Accompanying the Opening Testimony of Ed Burgess

Redacted PacifiCorp Response to Sierra Club Data Request 3.2

UE-400 / PacifiCorp
April 22, 2022
Sierra Club Data Request 3.2

Sierra Club Data Request 3.2

CONFIDENTIAL REQUEST - Please refer to PAC/200 at Owen/18:16-17, which states: "The Black Butte price for 2023 is estimated at [redacted]] due to recent increases in market coal prices".

(a) Please explain the discrepancy between this estimated price and the [redacted] price reported in line 12 and on Confidential Table 3.

(b) Does PacifiCorp expect this recent increase in market coal prices to similarly affect the contract price for Black Butte coal in May-December 2022 (i.e., beyond the [redacted]] deferred from 2021). If so, does PacifiCorp plan to request rate recovery of the difference between the actual May-December 2022 Black Butte coal costs and those estimated in the 2022 TAM?

Response to Sierra Club Data Request 3.2

(a) The [redacted] price cited is the estimated price for just the coal supply agreement, and the [redacted] price in Table 3 is the full delivered cost of coal including transportation.

(b) Actual Black Butte costs for May-December 2022 are anticipated to be [redacted]] than what was filed in the 2022 TAM, Docket No. UE 390. Filing for recovery of the difference between overall base and actual net power cost rates is a standard part of the power cost adjustment mechanism. However, for PacifiCorp to be allowed recovery of any cost increase or decrease, the amount must exceed the stipulated dead-band and earnings test.

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PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/115

Exhibit Accompanying the Opening Testimony of Ed Burgess

Public Data Responses from California Public Utilities Commission Proceeding No. A.21-08-004

Exhibit Sierra Club/115

Selected PacifiCorp Public Data Responses in A.21-08-004

1. PacifiCorp Response to Sierra Club Data Request 1.4
2. PacifiCorp Response to Sierra Club Data Request 1.5
3. PacifiCorp Response to Sierra Club Data Request 1.20
4. PacifiCorp Response to Sierra Club Data Request 1.24
5. PacifiCorp Response to Sierra Club Data Request 2.10
6. PacifiCorp Response to Sierra Club Data Request 5.2
7. PacifiCorp Response to Sierra Club Data Request 6.2
8. PacifiCorp Response to Sierra Club Data Request 7.1

A.21-08-004/ PacifiCorp
November 24, 2021
Sierra Club Data Request 1.4

Sierra Club Data Request 1.4

Please provide all coal price inputs, per coal plant, used in the AURORA model to forecast projected 2022 NPC. Please specify coal price tier.

(a) In this response, please explain how must-take coal quantities are priced in AURORA.

(b) If must-take coal quantities are priced as "$0," please explain whether PacifiCorp conducted any analysis that included the cost of must-take coal quantities. If so, please provide such analysis.

Response to Sierra Club Data Request 1.4

For coal price inputs, please refer to Confidential Attachment SC 1.4, specifically tab "yr_x".

(a) Must-take coal quantities are priced at "$0", and are included in the total fuel cost for each plant. This flat monthly expense is based on the annual must-take quantity cost divided by the 12 months of the year.

(b) The Company has not performed the requested analysis.

The confidential attachments are provided subject to the terms and conditions of the non-disclosure agreement in this proceeding between PacifiCorp and Sierra Club.

A.21-08-004/ PacifiCorp
November 16, 2021
Sierra Club Data Request 1.5

Sierra Club Data Request 1.5

Please explain whether the AURORA model allows the Company to input volumetric requirements for coal consumption from specific supplies.

(a) If the answer to the above is yes, please identify what volumetric requirements were imputed into AURORA by the Company;

(b) If volumetric requirements were imputed into AURORA, please explain whether the Company conducted an AURORA model that did not impose volumetric requirements. If so, please provide the results of said AURORA model run.

Response to Sierra Club Data Request 1.5

Yes, the AURORA model allows the Company to input volumetric requirements for coal consumption from specific supplies at the plant level. To further clarify, if there is more than one supply to a plant, the volumetric requirements for coal consumption is aggregated by plant, and input into the AURORA model.

(a) Minimum and maximum annual volumetric requirements are input into the AURORA model.

(b) The Company has not performed the requested analysis.

A.21-08-004/ PacifiCorp
November 16, 2021
Sierra Club Data Request 1.20

Sierra Club Data Request 1.20

Regarding the Company's unit commitment decision process for the coal units during this ECAC Period, indicate whether the Company performs a forward-looking economic analysis to inform its unit commitment decisions for its coal units (i.e., decisions regarding whether a particular generating unit will operate the next day up to its minimum economic level)?

(a) If not, explain why not.

(b) If so, provide all such analyses conducted during the ECAC Period in native, machine readable format.

Response to Sierra Club Data Request 1.20

No, the Company does not perform a forward-looking economic analysis for the purposes of the energy cost adjustment clause (ECAC) to inform its unit commitment decisions for its coal units.

(a) The analysis is not performed for purposes of the ECAC forecast because the AURORA model optimizes commitments for the entire time period contemplated by the study simultaneously (in other words, it does not optimize on a day-ahead basis, and then again on an hourly basis). In addition, coal fired units in the AURORA model used to prepare the net power costs estimate for this 2022 ECAC are modeled using a must-run setting to more closely reflect expected actual operations.

A.21-08-004/ PacifiCorp
November 16, 2021
Sierra Club Data Request 1.24

Sierra Club Data Request 1.24

Please describe whether and how the model and inputs used to determine the annual generation requirements for coal contract negotiation differs from the AURORA model and inputs used to calculate NPC.

Response to Sierra Club Data Request 1.24

PacifiCorp continually refines its process for development of generation forecasts used to support coal contract negotiations. Each new coal supply agreement (CSA) presents unique facts and circumstances. The current process uses the business plan generation forecasts as a starting point, and then additional Generation and Regulation Initiative Decision Tool (GRID) runs are performed as needed. Multiple PacifiCorp departments are involved in the generation forecast process including representatives from the fuel resources department, the energy supply management (ESM) department, the resources and commercial strategy department, and the ESM finance department.

The AURORA model is a production cost model developed by the vendor Energy Exemplar. This model has not yet been used for coal contract negotiation generation forecasts or for the business plan. Plans are in place to transition over to use the AURORA model for coal contract negotiations and the business plan. This transition is expected to occur in 2022. The AURORA model uses proprietary optimization and commitment logic that are likely different than the internally developed GRID optimization and commitment logic. Being completely different software applications, the input files, database, and system configurations are also different.

Currently, business plan GRID modeling is used for budgetary purposes, and the AURORA model is used to forecast net power costs (NPC). GRID and AURORA are two separate models utilized for different purposes at different times of the year, and potentially different forecast periods. The inputs to the GRID model for coal contract negotiations are intended to try to capture recent market trends and volatility, whereas the AURORA runs utilize more normalized inputs for NPC forecasting.

A.21-08-004/ PacifiCorp
January 7, 2022
Sierra Club Data Request 2.10

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.

A.21-08-004/ PacifiCorp
February 14, 2022
Sierra Club Data Request 5.2

Sierra Club Data Request 5.2

Please identify the range of production and coal delivery levels considered when developing the base BCC mine plan for the 2020, 2021, and 2022 ECACs.

Response to Sierra Club Data Request 5.2

The Company assumes that the reference to the "2020, 2021, and 2022 ECACs" is intended to be references to this current proceeding, Application (A) 21-08-004 (the 2022 Energy Cost Adjustment Clause (ECAC), proceeding A.20-08-002 (the 2021 ECAC), and proceeding A.19-08-002 (the 2020 ECAC). Based on the foregoing assumption, the Company responds as follows:

There are no ranges of production and coal delivery levels that are considered specifically for PacifiCorp's ECAC proceedings.

A.21-08-004/ PacifiCorp
February 25, 2022
Sierra Club Data Request 6.2

Sierra Club Data Request 6.2

For estimated Naughton and Black Butte coal supply prices included to calculate the forecast NPC for calendar year 2022:

(a) Please explain whether these coals supply prices are meant to represent anticipated 2022 costs. If not, explain what these prices are meant to represent.

(b) Please explain, in detail, how these coal supply prices were developed.

(c) Did PacifiCorp develop a generation forecast and/or fueling budget to develop the estimated prices?

i. If so, please provide such forecasts and/or budgets.

ii. If not, explain why not.

(d) Please explain in detail how generation forecasts were developed, including any tools, models, or simulated used (e.g., GRID, AURORA).

(e) Please provide any key assumptions used in developing the Naughton and Black Butte estimated prices, including:

i. Minimum take requirements;

ii. Minimum burn or must-run constraints;

iii. Fuel price assumptions; and

iv. Whether the fuel price assumptions reflected the average or incremental fuel cost.

(f) Please provide a comparison between the estimated Naughton and Black Butte prices used in the 2022 ECAC and Naughton and Black Butte prices used in the 2021 ECAC.

Confidential Response to Sierra Club Data Request 6.2

(a) The prices for Naughton and Black Butte are estimates of anticipated costs to purchase coal from these sources in 2022.

(b) For Black Butte, the existing contract pricing was used for January 2022 through April 2022. For Black Butte for May 2022 through December 2022, and for Naughton, coal pricing estimates were developed based on conversations with the coal suppliers and the Company's professional judgement.

(c) No. PacifiCorp did not develop generation forecasts in order to estimate coal prices from the Naughton and / or Black Butte coal fuel sources.

i. Not applicable.

ii. Estimated coal prices are an input used to develop generation forecasts.

(d) Please refer to the Company's response to Sierra Club Data Request 4.6 subpart (d).

(e) The assumptions used are:

i. Minimum take – [redacted] tons for Naughton, and [redacted] tons for Black Butte.

ii. Minimum burn – [redacted] million British thermal units (MMBtu) for Naughton, and [redacted] MMBtu for Black Butte.

iii. Price – [redacted] per ton ($/ton) for Naughton, and [redacted] January 2022 through April 2022 and [redacted] May 2022 through December 2022 for Black Butte.

iv. Incremental pricing was used to determine the amount of coal consumption at the plant, then subsequently the average coal inventory price was used to calculate forecasted net power costs (NPC).

(f) For clarification purposes, the Company interprets "2022 ECAC" to be a reference to this energy cost adjustment clause (ECAC) proceeding (Application (A) 21-08-004) for the forecast period calendar year 2022. The Company further interprets "2021 ECAC" to be a reference to the previous ECAC proceeding (A.20-08-002) for the forecast period calendar year 2021. Based on the foregoing interpretation, the Company responds as follows:

The forecast coal prices used in the 2021 ECAC proceeding (A.20-08-002) for calendar year 2021 for Naughton and Black Butte coal were [redacted] respectively. The forecast coal prices used in this 2022 ECAC proceeding

(A.21-08-004) for calendar year 2022 are [redacted] for Naughton. For Black Butte coal, the prices used are [redacted] January 2022 through April 2022, and [redacted] May 2022 through December 2022.

Confidential information is provided subject to the terms and conditions of the non-disclosure agreement (NDA) in this proceeding between PacifiCorp and Sierra Club.

A.21-08-004/ PacifiCorp
March 1, 2022
Sierra Club Data Request 7.1

Sierra Club Data Request 7.1

For estimated Naughton and Black Butte coal supply prices included to calculate the forecast NPC for calendar year 2022:

(a) Please confirm whether the 2022 Naughton and Black Butte coal supply prices were based upon the 2021 ECAC assumptions for calendar year 2021. If so, please provide the 2021 ECAC assumptions.

(b) Please confirm whether the 2022 Naughton and Black Butte coal supplies were subject to the same take-or-pay volume amounts as the 2021 ECAC assumptions for calendar year 2021. If so, please provide the 2021 ECAC assumptions.

(c) Please describe whether the 2021 pricing assumptions for Naughton and Black Butte used in the previous GRID model were used to inform the pricing input assumptions used in AURORA for 2022. If so, please explain how the previous GRID assumptions were used in AURORA and any adjustments made to them.

Response to Sierra Club Data Request 7.1

For clarification purposes, the Company interprets "2021 ECAC" to be a reference to the previous ECAC proceeding (A.20-08-002) for the forecast period calendar year 2021. Based on the foregoing interpretation, the Company responds as follows:

(a) Not confirmed. The assumptions for estimated coal supply prices for Naughton and Black Butte used in the forecasted net power costs (NPC) for calendar year 2021 (2021 ECAC), and the assumptions used in the forecasted NPC for calendar year 2022 in this proceeding (2022 ECAC) are different because the existing coal supply agreement (CSA) for Naughton expired in December 2021, and the Black Butte CSA expires in April 2022.

(b) Not confirmed. As stated in the Company's response to subpart (a) above, the forecasted NPC for calendar year 2021 (2021 ECAC), and the assumptions used in the forecasted NPC for calendar year 2022 in this proceeding (2022 ECAC) are different because the assumptions used for the take-or-pay amounts are based on the applicable CSAs.

(c) Please refer to the Company's response to subpart (a) above for pricing assumptions for Naughton and Black Butte. The calendar year 2021 fuel price forecasts used in the Generation and Regulation Initiative Decision Tool (GRID) for the 2021 ECAC were not used as the calendar year 2022 fuel price forecasts inputs for the Aurora model.

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/116

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 3.6 “Attach SC 3.6 CONF”

This exhibit is confidential pursuant to Protective Order No. 16-128.

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Docket No. UE 400
Exhibit Sierra Club/117
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/117

REDACTED

Exhibit Accompanying the Opening Testimony of Ed Burgess

Redacted PacifiCorp Response to Sierra Club Data Request 5.8

UE-400 / PacifiCorp
May 17, 2022
Sierra Club Data Request 5.8

Sierra Club Data Request 5.8

HIGHLY CONFIDENTIAL REQUEST - Please refer to the April 15, 2022 Jim Bridger Long Term Fuel Plan Update, Appendices 13-18.

(a) Do the numbers in these tables correspond to PacifiCorp's share of the Jim Bridger fueling costs or the plant total?

(b) Do the base tons received in 2023 correspond to the mine plans identified in SC 2.9? For example, referring to Appendix 16, does the [redacted] of BCC Base received in 2023 correspond to the [redacted] delivered in the "Opt. 1&2H 3.38 Plan - Nov 4.0 Fcst" mine plan (i.e., the base mine plan), or any other mine plan provided in SC 2.9?

(c) Please identify the BCC mine plan in SC 2.9 that corresponds to each scenario in Appendices 13-18.

Highly Confidential Response to Sierra Club Data Request 5.8

(a) The numbers in these tables reflect PacifiCorp's share.

(b) As noted in the Company's response to Sierra Club Data Request 2.9, "Opt. 1&2H 3.38 Plan – Nov. 4.0 Fcst" is Bridger Coal Company's (BCC) base plan that was used to inform Jim Bridger plant fuel costs in this 2023 transition adjustment mechanism (TAM). This plan was also used in Scenario 4 in the PacifiCorp Highly Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant (updated April 15, 2022).

(c) Scenarios in the Jim Bridger Plant Long-Term Fuel Plan updated in April 2022 and the corresponding BCC mine plans are identified below:

[redacted]

[redacted]

[redacted]

UE-400 / PacifiCorp
May 17, 2022
Sierra Club Data Request 5.8

[redacted]

Highly confidential information is designated has Highly Protected Information under the Modified Protective Order 22-063 in this proceeding and may only be disclosed to qualified persons as defined in that order.

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

EXHIBIT SIERRA CLUB/118

REDACTED

Exhibit Accompanying the Opening Testimony of Ed Burgess

Selected PacifiCorp Responses to ALJ Bench Requests in LC 77

LC-77 / PacifiCorp
March 3, 2022
ALJ Bench Request 1

ALJ Bench Request 1

Staff Recommendation #7, Sensitivity Removing Take or Pay Assumptions: For the results of PacifiCorp's sensitivity that removes any take or pay assumptions in PLEXOS in any years after there is an existing contract:

(a) Compare the level of dispatch of each thermal plant and other resource types in the sensitivity versus the preferred portfolio.

(b) Report the fuel cost savings at Jim Bridger 3 and 4 by year.

(c) Explain when Jim Bridger 3 and 4 provide the highest value: *i.e.*, which months and hours have the highest capacity value and what is that capacity value?

(d) Explain when in the year (which hours and months or which system conditions) the reliability of the system requires the full output of the Jim Bridger units in key years, such as in 2025, after the 2020 All-Source Request for Proposal (2020AS RFP) final shortlist resources have come online.

Confidential Response to ALJ Bench Request 1

Referencing the Public Utility Commission of Oregon (OPUC) staff's Final Comments Report dated February 11, 2022, specifically, OPUC staff's requested sensitivity removing take-or-pay assumptions as discussed on pages 9 through 13, the Company responds as follows:

The Company notes that while OPUC staff's requested sensitivity is ultimately concerned with the inclusion of Jim Bridger minimum take assumptions in the 2021 Integrated Resource Plan (IRP) preferred portfolio, the 2021 IRP preferred portfolio is not the appropriate study for comparison. The study design in development leading up to OPUC staff's Final Comments used P02-MM rather than the 2021 IRP preferred portfolio for reasons which OPUC staff articulates and finds reasonable on page 13 of their Final Comments Report, which states "Staff finds that, if the intent is to make sure that each state is assigned the costs associated with its legislative requirements instead of sharing costs of state-specific policy among jurisdictions, then this response is reasonable". The Company also notes that OPUC staff's sensitivity requested additional endogenous modeling of coal retirement options for Jim Bridger Unit 3 and Jim Bridger Unit 4, Huntington Unit 1 and Huntington Unit 2, and Naughton Unit 1 and Naughton Unit 2.

With the foregoing understanding and clarification, the Company responds as follows:

(a) In the 2021 IRP, PLEXOS long-term (LT) modeling selected Jim Bridger Unit 3 and Jim Bridger Unit 4 to run and generate energy that included fuel take-or-pay obligations through end-of-life. In the requested Oregon sensitivity, which allows for additional endogenous retirement options and removes fuel take-or-pay obligations,

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PLEXOS LT optimization of the P02-MM study continues to select Jim Bridger Unit 3 and Jim Bridger Unit 4 to run on coal and generate energy through the existing end-of-life in 2037. PLEXOS considers the early retirement of Jim Bridger Unit 3 and Jim Bridger Unit 4 incurring accelerated decommissioning costs and incurring replacement resources costs to be unfavorable to customers.

In the Oregon sensitivity outcome, the operation of Jim Bridger Unit 3 and Jim Bridger Unit 4 through 2037 provide quantifiable and valuable risk mitigation to the system. This is especially apparent in the timeframe 2030 and beyond. Results of the medium-term (MT) stochastic model demonstrate that volatility pushes both units to operate in all years in 96 percent of all stochastic iterations, generating energy to cover variations in load, hydro, electric prices, natural gas prices and outages in order to address system risk. The value of this risk mitigation to the system is brought into the short-term (ST) deterministic results through the risk-adjustment, contributing to the risk-adjusted present value of revenue requirements (PVRR) used to rank competing outcomes.

While the models continue to indicate the value of Jim Bridger Unit 3 and Jim Bridger Unit 4's ongoing operation, there is additional benefit if the modeling assumes there will be "complete fueling freedom", i.e. that there will be no contractual obligations of any kind for future fueling beyond current contracts. This additional benefit assumes adequate and reliable coal supply would be available on demand, and that this fuel supply could be achieved without significant capital to retrofit the plant for the safe delivery and handling of large volumes of Powder River Basin (PRB) coal to replace the existing coal supply. This is an unrealistic scenario as coal suppliers require some assurance that the supplier can cover the costs to produce the coal and maintain an adequate workforce, which is typically done through minimum take-or-pay provisions in a contract. With this unconstrained assumption, there are no retirement changes and limited resource changes in years 2030 and beyond; however, complete fueling freedom generates a net system benefit of $156 million present value of revenue requirements differential (PVRR(d)) when compared to top performing case P02-MM.

Studies to determine the additional capital investment at Jim Bridger to enable deliveries of sufficient PRB coal to fuel the plant were calculated in the last Jim Bridger Long-Term Fuel Plan. The studies conducted in 2018, and refreshed in 2019, estimated that [redacted]

Because the Oregon sensitivity portfolio continues to include Jim Bridger Unit 3 and Jim Bridger Unit 4 through end-of-life, one important impact of this outcome is that it indicates a reduction in cost in the P02-MM, assuming only small changes, of an additional $156 million. This significantly increases the system benefit of P02-MM when compared to the P02h variant (where Jim Bridger Unit 3 and Jim Bridger Unit 4 are retired early). The $60 million in P02-MM benefits may rise as high as $216 million in simple PVRR(d), which would be mitigated somewhat by changing P02h take-or-pay assumptions to match over a shorter lifespan.

These savings are theoretical in the sense that the Company is currently unable to produce coal at the Jim Bridger mine without covering its capital, operating, and reclamation costs, or contract coal supplied by a third-party with no contractual obligations of any kind – however, PacifiCorp will continue to evaluate options for Jim Bridger Unit 3 and Jim Bridger Unit 4 as part of its coal supply procurement and in the 2023 IRP.

While these Oregon sensitivity results are instructive as to the need for further evaluation of the long-term operation of Jim Bridger Unit 3 and Jim Bridger Unit 4, they do not account for other factors that could impact ongoing operation of the units. For example, the state of Wyoming has required PacifiCorp to issue a request for proposals (RFP) for the installation of carbon capture technology on Jim Bridger Unit 3 and Jim Bridger Unit 4 for the purpose of controlling carbon emissions from the units assuming they continue to operate on coal. PacifiCorp must issue this RFP in 2022 and after receiving responses, it must evaluate how meeting Wyoming's carbon capture requirements will impact fueling plans for Jim Bridger Unit 3 and Jim Bridger Unit 4.

The theoretical results of the Oregon sensitivity also indicate the need for evaluation of a potential conversion of the units to natural gas-fueled operations. PacifiCorp intends to evaluate a natural gas conversion alternative in subsequent sensitivities and IRPs. Additional alternatives (as recently discussed at the Company's February 25, 2022 public input meeting for the 2023 IRP) may also include conversion to hydrogen, ammonia or bio-fueled operations.

In addition to the possibilities of favorable fuel contracts, many factors including risk are expected to play a role in the economics of Jim Bridger Unit 3 and Jim Bridger Unit 4 operations in the next several years. A few of these risk factors include more recent information on market depth and pricing, increases in system load, the economics of fuel-type conversions, emissions and environmental legislation.

Please refer to Confidential Attachment ALJ Bench Request 1-1, reporting Jim Bridger Unit 3 and Jim Bridger Unit 4 generation assuming no minimum take-or-pay obligations across the LT, MT and ST models as compared to outcomes of the P02-MM study as filed in the 2021 IRP.

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(b) Please refer to Confidential Attachment ALJ Bench Request 1-2 which provides fuel costs savings removing Jim Bridger take-or-pay fuel.

(c) PacifiCorp has not calculated a "value of capacity" specific to individual hours in the requested study. However, the greatest resource need typically coincides with the highest energy and operating reserve values, as increasing prices indicate fewer and fewer high-cost resource options are all that remains available. For details on the hourly marginal energy and operating reserve values applicable to resources located at Jim Bridger, please refer to Confidential Attachment ALJ Bench Request 1-3. Note: these values are based on expected conditions in the ST model, and do not account for stochastic variation in load, hydro, or thermal unit availability which would result in significantly higher resource needs in some periods. In general, the periods with the highest marginal energy and operating reserve values in the ST model would be reasonably aligned with the periods in which resource need would be the highest in a stochastic analysis.

(d) Please refer to Confidential Attachment ALJ Bench Request 1-4 which provides the hourly generation and operating reserve provision of Jim Bridger Unit 3 and Jim Bridger Unit 4 in the requested study. To maintain reliable operation and comply with reliability standards, PacifiCorp must serve load and maintain operating reserves. As a result, resources that are providing operating reserves contribute to system reliability even if they are not dispatched to their maximum operating level. In addition, in order to maintain reliability, additional resources must be available to serve load and maintain operating reserves even if load, hydro, or thermal availability change in an adverse manner. PacifiCorp has not performed stochastic analysis of reliability to evaluate the impact of variations in load, hydro, or thermal availability specific to this study, which reflects expected conditions. However, an hourly stochastic reliability analysis was recently conducted in Docket UM 2011 (General Capacity Investigation), based on a portfolio that is similar to that requested and for the years 2024, 2028, 2032, 2036, and 2040. The results of that analysis were provided in that docket, and for convenience, a copy is provided here as Attachment ALJ Bench Request 1-5 and Confidential Attachment ALJ Bench Request 1-6. Note: PacifiCorp has provided an additional summary within Attachment ALJ Bench Request 1-5 highlighting the timing of periods with reliability concerns over time.

In 2024, reliability concerns are highest in the afternoon and evening in July. In 2028, August and September evenings have a higher reliability risk than July, while in 2032 reliability risks continue to shift toward the nighttime in a number of months. In 2036, reliability risks are primarily in the evening and overnight in July through September. In 2040, reliability risks are primarily during winter mornings and evenings. The change between 2036 and 2040 is in part related to the retirement of thermal resources totaling approximately 2,800 megawatts (MW), including two Huntington units, four Bridger units, Wyodak, and Hermiston.

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Analysis Supporting the Assumptions Used in the IRP:

(a) Please address whether inclusion of minimum take levels for the coal plants has increased the forecasted level of market sales in the preferred portfolio. Include a discussion of the assumptions, such as fuel cost, influencing PLEXOS' decisions regarding when and for what purpose to dispatch coal plants before minimum take levels are reached.

(b) Referencing Sierra Club's Confidential Table 3, please detail the analysis performed to arrive at the minimum take levels assumed for Jim Bridger.

(c) Please specifically address the reasons for the changes in the minimum take level at the third-party mine shown in Sierra Club's Confidential Table 3.

Confidential Response to ALJ Bench Request 6

(a) The Jim Bridger fuel assumption modeling included a take-or-pay tier and volumes within this tier have zero incremental fuel cost. Greenhouse gas (GHG) emissions costs continue to apply, so as part of system dispatch the Jim Bridger coal-fired resources would generally be dispatched up whenever the locational marginal price (LMP) exceeded their emissions cost, up to the annual take-or-pay volume. The Jim Bridger take-or-pay modeling thus results in a lower dispatch price for Jim Bridger than it would otherwise have. This results in higher Jim Bridger dispatch offset by a combination of reduced output from other resources, reduced market purchases, and increased market sales, depending on the marginal source of supply (or demand in the case of market sales) in each period. Please refer to the Company's response to ALJ Bench Request 1, specifically Confidential Attachment ALJ Bench Request 1-1, which details market activity in each study. Fuel volume discussion continues in the Company's response to subpart (b) below.

(b) The minimum take levels for the Bridger Coal Company (BCC) are based on the production levels associated with a "1 dragline operation", which represents the lowest level of production at the mine that would likely be economic.

The minimum take levels for Black Butte Coal Company (BBCC) are based on discussions with BBCC regarding various production levels ranging from [redacted] million tons. Because Jim Bridger plant is [redacted] PacifiCorp's 2021 Integrated Resource Plan (IRP) assumes a minimum BBCC production volume of [redacted]

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[redacted] million tons each year, which is at the low end of the production volumes identified by BBCC.

Consistent with Idaho Power Company's (IPC) 2019 IRP, PacifiCorp's 2021 IRP assumes IPC participates in the BBCC contract through 2030 and no longer participates in the plant or BBCC contract beginning in 2031. Consistent with the current coal supply agreement (CSA), PacifiCorp's 2021 IRP assumes PacifiCorp takes [redacted] of BBCC's coal production through 2030. Beginning in 2031, the 2021 IRP assumes PacifiCorp takes [redacted] of the assumed minimum BBCC production volume.

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

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ALJ Bench Request 7

Explanation of the Selection of the Preferred Portfolio over a Variant:

(a) Please describe, with specificity, the reasons for the $60 million difference between the portfolios described at page 13 of the Staff Report. Include a discussion of whether market sales contribute to the difference.

(b) Describe the technology or resource type of the next marginal resource the model can select instead of Jim Bridger 3 and 4.

i. Provide the capital, fixed, and variable operating cost and the potential contribution to market sales revenue of the next marginal resource compared to the fixed and variable costs of continuing to run Jim Bridger.

Response to ALJ Bench Request 7

(a) The portfolio changes between "P02h" when Jim Bridger Unit 3 and Jim Bridger Unit 4 are forced to retire before 2030 less "P02-MM" are reported in PacifiCorp's 2021 Integrated Resource Plan (IRP), Volume I, Chapter 9 (Modeling and Portfolio Selection Results), on page 287 and Figure 9.28 (Increase/(Decrease) in Proxy Resources when Jim Bridger Units 3 and 4 are Forced to Retire before 2030). When Jim Bridger Unit 3 retires, 200 megawatts (MW) of solar co-located with storage is added to the portfolio. When Jim Bridger Unit 4 retires, an additional advanced nuclear resource is added in 2030. These additions displace a 2038 advanced nuclear resource and a 2038 non-emitting peaker, which are included in the "P02-MM" portfolio. The supporting confidential work paper for Figure 9.28, including the portfolio difference, is provided on the confidential data disk accompanying the 2021 IRP, specifically folder "Chapters and Appendices CONF\Chapter 9 - Modeling and Portfolio Selection Results", file "CONF Figure 9.28 21IRP 20yr_P02-MM JB-RET (15283) less 21IRP 20yr_P02-MM (5230)".

For the present value of revenue requirements differential (PVVR(d)), please refer to the confidential data disk accompanying the 2021 IRP, specifically folder "Chapters and Appendices CONF\Chapter 9 - Modeling and Portfolio Selection Results", file "CONF Figure 9.29 - P02h - JB3-4 Retire", tab "Summary".

Effectively, the costs to add replacement proxy resources (proxy capital recovery and proxy fixed costs) exceeded the cost to continue operating Jim Bridger Unit 3 and Jim Bridger Unit 4 (coal fuel costs, emissions cost, non-gas variable operations and maintenance (VOM), risk adjustment offset by higher system balancing market sales, other costs, and lower gas fuel cost) for a total of $60 million.

For ease of reference, copies of the above referenced confidential work papers are provided herewith as Confidential Attachment ALJ Bench Request 7-1, and

PacifiCorp's 2021 IRP, Volume I can be accessed by utilizing the following website link:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

(b) In the absence of reliability needs, the next marginal resource the model can select at the Bridger brownfield site to replace Jim Bridger Unit 3 and Jim Bridger Unit 4 is Solar+Storage. However, this resource contributes neither adequate capacity, nor duration of energy to meet reliability to wholly replace these two resources during periods with shortfalls. As a result, resources that can provide both higher maximum capacity **AND** long duration of energy during those periods are limited to Non-Emitting Peaker and Nuclear resources.

i Please refer to Attachment ALJ Bench Request 7-2 which provides the annual costs for the non-emitting peaker, nuclear and Solar+Storage resources in the "P02-MM H" variant case. Net resource costs are provided on tab "Generator", in column AJ. These net costs are annualized build costs less revenue net of fixed operations and maintenance (FOM) costs. The revenue in the calculation includes battery revenue, as applicable. Resource values vary by year based on the value of the generation they provide during a given time period.

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EXHIBIT SIERRA CLUB/119

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.16 “Attach ALJ Bench Request 1-1 CONF”

This exhibit is confidential pursuant to Protective Order No. 16-128.

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EXHIBIT SIERRA CLUB/120

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Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.11

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