PACIFIC POWER
A DIVISION OF PACIFICORP

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June 22, 2022

VIA ELECTRONIC FILING

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

Re: UE 400—PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Michael G. Wilding, Ramon J. Mitchell, Daniel J. MacNeil, James Owen, Seth Schwartz, and Zepure Shahumyan.

Included with this filing are electronic workpapers, which have been uploaded to Huddle. Confidential and highly confidential material in support of the filing has been provided to parties under Order No. 16-128 and Order No. 22-063.

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

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **2023 Transition Adjustment Mechanism Reply Testimony** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 22nd day of June, 2022.

Jennifer Angell

Jennifer Angell
Regulatory Project Manager

REDACTED
Docket No. UE 400
Exhibit PAC/500
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Michael G. Wilding

June 2022

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

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the opening testimony of Moya Enright and Madison Bolton, filed on behalf of Staff, Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB), and Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC).

Q. Please identify the witnesses providing reply testimony supporting the 2022 TAM.

A. In addition to my testimony, the following witnesses are providing reply testimony in support of the Company's 2023 Transition Adjustment Mechanism (TAM) filing:

- Company witness Ramon Mitchell, Manager, Net Power Costs, responds to arguments raised by parties regarding the modeling of net power costs (NPC) and updates the Company's NPC recommendation since the initial filing (Reply Update).
- Company witness Daniel J. MacNeil, Commercial Analytics Adviser, responds to testimony regarding certain modeling issues related to the regulation reserve, Naughton plant coal supply agreement (CSA) analysis, and the integrated resource plan.

- Company witness James Owen, Vice President of Environmental, Fuels and Mining, testifies in support of the prudence of the Company's CSAs, and responds to the concerns raised by parties regarding PacifiCorp's coal-fueled resources.
- Company witness Seth Schwartz, President, Energy Ventures Analysis, Inc., provides testimony supporting the analysis that was conducted on PacifiCorp's Huntington plant CSA.
- Company witness Zepure Shahumyan, Director, Energy and Environmental Policy, provides an overview of the impact of Washington Cap-and-Trade law for NPC in Oregon.

Q. Please summarize your testimony.

A. Through my testimony, I address the following issues:

- I discuss some of the challenges currently facing the Company to provide some overall context on the scope of this rate increase and the modeling refinements that have been proposed by PacifiCorp;
- I explain when the final economic data will be available to calculate the production tax credit (PTC) rate for 2023, and discuss how PacifiCorp is continuing to monitor the data that is available;
- I respond to the concerns from the CUB regarding rate shock and explain how increasing prices in the power and natural gas markets are driving increased power costs, and how reflecting these increased costs in the forecast is important to prevent other adverse outcomes in future proceedings;
- I address the inaccuracies in AWEC's arguments regarding how to account for Utah load, the Public Service Company of Colorado (PSCo) contract, and explain

the process for incorporating the benefits from the Northwest Pipeline rate case at the Federal Energy Regulatory Commission (FERC);

- Finally, I respond to Calpine to explain the timing for modeling of the Schedule 296 calculation.

II. REPLY TO STAFF

A. Overall Context

Q. PacifiCorp's NPC modeling in the reply update is showing a 6.8 percent increase from the Company's initial filing. Can you provide some context?

A. Yes, the Company acknowledges the magnitude of the proposed increase in this case and the impact on customer rates. As discussed in the Reply Update, however, the majority of the cost increase results from market dynamics that are outside the Company's control, including rapidly increasing natural gas and electric market prices. Between December 2021 and March 2022, market prices have increased by 123 percent. Company witness Mitchell describes these trends in more detail in his testimony as part of the Reply Update completed by the Company. The current market environment is unprecedented and is creating cost pressure throughout the utility industry. The west is continually facing issues on regional resource adequacy, drought conditions, unexpected weather events. Additionally, new regulations like Washington Cap and Trade, and the Environmental Protection Agency's proposed Ozone Transport Rule (OTR), the impacts of which have not been included in the TAM, create further uncertainty. All these items combine are putting upward pressure on NPC and making it increasingly difficult to forecast NPC.

The Company, however, has been able to mitigate the adverse impact of the current market in large part because of its diverse generation mix and aggressive cost containment efforts. This increased coal generation acting to offset rising prices is described in more detail in the testimony of Company witness Mitchell. Additionally, by ensuring access to zero-fuel-cost renewable generation and low, fixed cost coal generation, the Company has contained what could otherwise have been an even greater rate increase.

Q. Staff claims that 51 percent of the proposed rate increase in the 2023 TAM reflects modeling changes recommended by PacifiCorp.[1] Why has the Company recommended refinement to the NPC modeling used in the TAM?

A. The purpose of the TAM is to "achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year."[2] In recent years, however, as shown in Figure 1 and Table 1 the Company has persistently under-recovered its NPC in Oregon rates:

[1] Staff/100, Enright/4.
[2] *In re PacifiCorp, dba Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).

FIGURE 1

Oregon NPC Collected in Rates versus Actual NPC[3]

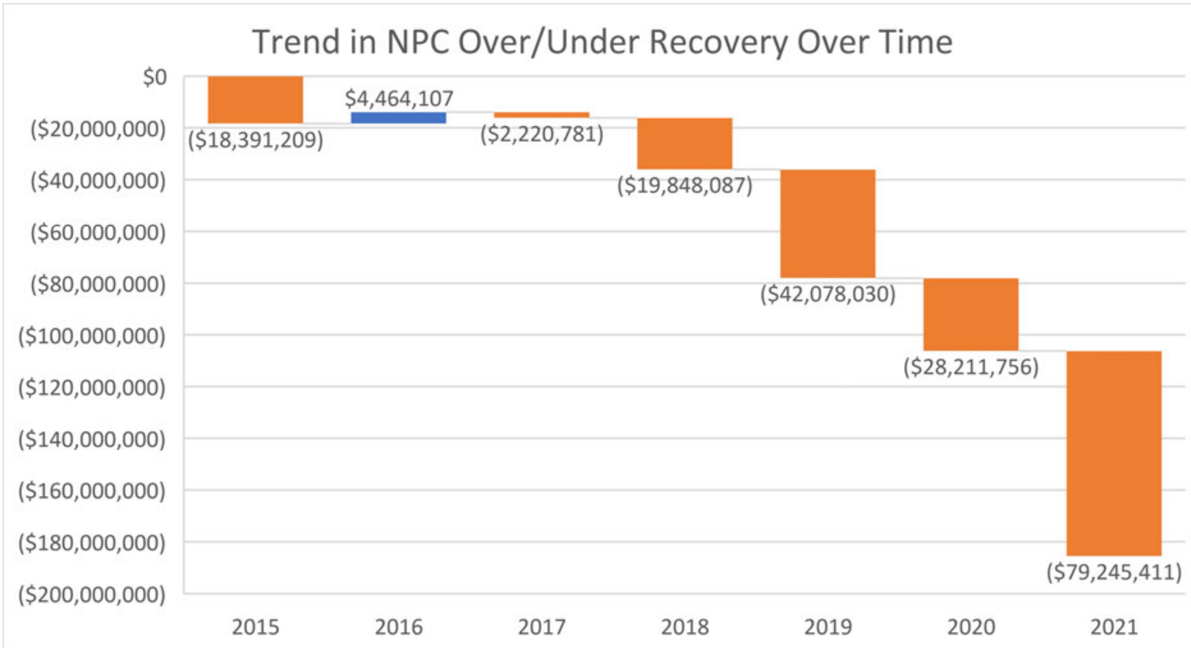

TABLE 1

Oregon NPC Collected in Rates versus Actual NPC[3]

Year	NPC Collected Through Rates	Actual NPC	Over/(Under) Recovery of NPC ($)	Over/(Under) Recovery of NPC (%)
2015	$343,993,011	$362,384,220	$(18,391,209)	(5)%
2016	$347,055,570	$342,591,463	$4,464,107	1%
2017	$340,640,219	$342,861,000	$(2,220,781)	(1)%
2018	$334,683,850	$354,531,937	$(19,848,087)	(6)%
2019	$340,850,405	$382,928,436	$(42,078,030)	(11)%
2020	$307,368,806	$335,580,562	$(28,211,756)	(8)%
2021	$281,150,581	$360,395,991	$(79,245,411)	(22)%

Note: Beginning in 2017, PTCs have been included in the TAM and NPC.

[3] The calculation of 2016 actual NPC used for the analysis performed in this testimony does not include certain coal costs that were excluded in the TAM. The exclusion of these costs from actual NPC shows a small over-recovery of NPC in 2016. If these costs were included in actual NPC, it would show a small under-recovery in 2016.

The Company's under-recovery has persisted even as the Commission has approved modeling refinements, such as the day ahead real time adjustment, that are intended to capture costs that were previously excluded from the forecast. The Company's transition to Aurora may help narrow the gap between forecasted and actual NPC, but to do so effectively requires refining the Aurora model and tailoring it to fit PacifiCorp's specific circumstances. To that end, the Company has proposed several modeling refinements aimed at improving the accuracy of the NPC forecast. While the modeling refinements increase the forecasted NPC, that increase will produce a more accurate forecast, consistent with the purpose of the TAM. A more accurate forecast will also provide better price signals to customers on the costs of power consumption and support more efficient use of energy and conservation measures.

B. PTCs

Q. Staff proposes an adjustment to reflect the expectation that the PTC will increase from 2.7 to 2.8 cents per kilowatt-hour (kWh) in 2023 based on current levels of inflation.[4] How Do you respond?

A. The PTC rate for 2022 is 2.6 cents/kWh.[5] Staff has correctly identified preliminary economic data that suggests the PTC rate will likely be higher in 2023. The final economic data that determines the 2023 rate will not be published until March of 2023. PacifiCorp will continue to monitor the economic data as more information comes available close to the final update. Preliminary data is published monthly, and PacifiCorp continues to monitor this data for the probable outcome.

[4] Staff/400, Bolton/2.
[5] 87 Fed. Reg. 27204 (May 6, 2022).

C. Extended Day Ahead Market (EDAM)

Q. Staff recommends that the Company provide additional information regarding its potential participation in an EDAM.[6] What are Staff's specific recommendations?

A. Staff recommends that the Commission require PacifiCorp to provide the following:

a. Quarterly updates on the progress of the EDAM project, beginning in December 2022, including details of PacifiCorp's involvement in the stakeholder process, the expected implementation timelines for EDAM, and detail of PacifiCorp's intentions and timeline for EDAM participation.

b. Testimony in the 2024 TAM detailing the benefits the Company expects to accrue from its EDAM participation, and how such benefits will be reflected in customer rates.

c. Testimony in the 2024 TAM regarding any costs the Company requests recovery for in relation to its EDAM participation, including an itemized breakdown of costs, identifying both variable and fixed costs separately, and including detail of the basis for the Company's cost forecast.

d. A workshop held prior to the filing of the 2024 TAM, in which PacifiCorp should present on the issues detailed at (b) above.

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

A. The Company largely does not object to Staff's recommendations but believes they seem onerous and outside the scope of a TAM. The Company further notes that the Commission's policy Staff has already requested EDAM status updates and the Company has agreed to provide those updates. It is unclear if Staff in this case is requesting something additional and duplicative.

[6] *See* Staff/100, Enright/26-27.

III. REPLY TO CUB

A. Rate Shock

Q. CUB is concerned that the proposed rate increase in this case, coupled with the potential rate increases from the Company's power cost adjustment mechanism (PCAM), general rate case, and pending wildfire and COVID-19 deferrals, will cause rate shock.[7] How do you respond to this concern?

A. The Company understands CUB's concern and takes seriously the impact on customers associated with rate increases of any magnitude. In this case, however, the increased rates are largely the product of forces that are outside the Company's control, like current market conditions, and reflective of the costs to serve customers. As noted above, the purpose of the TAM is to accurately forecast NPC even when that forecast increases rates because of expected market conditions. Furthermore, artificially dampening the costs of power creates inefficient price signals to customers and undermines the potential value of conversation measures and efforts.

Setting accurate NPC is also critical in the TAM because significant under-recovery will lead to rate increases in subsequent years through the PCAM. Indeed, CUB cites the proposed rate increase in the 2021 PCAM to support its concern over rate shock. To avoid compound rate increases such as the one that is occurring this year because of the under-recovery in 2021, it is essential that NPC be accurately forecast even if the forecast results in a rate increase.

Q. Is rate shock a reasonable basis for decreasing the NPC forecast in this case?

A. No. It is my understanding that the Commission has rejected the argument that rate

[7] CUB/100, Jenks/2.

shock is a legitimate basis to disallow costs, as the Commission explained in Order No. 01-988 when it rejected a CUB argument to disallow costs to reduce the magnitude of a rate increase:

> This Commission has broad authority to supervise and regulate every public utility and has a duty to represent the customers of any public utility and the public in general in all controversies regarding rates. In exercising this authority, we carefully review a utility's costs to ensure that rates charged to customers are fair, just, and reasonable. We also consider the impact of rate increases on customers when setting new rates. *The law does not permit us, however, to use rate shock as a tool to authorize a revenue requirement that is unreasonably low.* Rates must be sufficient for the utility to maintain financial viability and the capability to fulfill its obligation to provide electricity to customers in its service territory. Accordingly, this Commission must allow a utility the opportunity to recover increased operating expenses that are prudently incurred. We cannot ignore the importance to ratepayers of maintaining the financial viability of the utility. Contrary to the Joint Parties' assertions, this Commission has not previously used rate shock to reject prudently incurred expenses. *"Rate shock" is not a legal principle; rather, it is a factor the Commission has considered in the rate spread and rate design stage of various rate proceedings.* When allocating a utility's revenue requirement among customer classes, the Commission has pursued—where possible—a policy of gradualism by avoiding substantial rate increases for any particular customer class.
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> * * *
>
> We conclude that the Joint Parties' rate shock argument has no basis in law. *Rate shock is a relevant factor in the rate design stage of the case; it plays no role in determining a utility's revenue requirement*.[8]

Q. Has CUB proposed any specific adjustment based on its concern over rate shock?

A. It is unclear. When testifying about the Company's modeling refinements, CUB

[8] *In re of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-988 at 5-6 (Nov. 20, 2001) (emphasis added).

argues that "review of these modeling changes must be done in the context of the rate shock expected when these prices get passed through to customers," and therefore, according to CUB, "[m]odeling changes that increase rates but are not clearly required should be rejected."[9] So it appears that CUB's opposition to specific adjustments may be based on concerns over rate shock, not the accuracy of the adjustment. Additionally, the PCAM dead bands, sharing bands, and earnings test have resulted in asymmetrical under-recovery of NPC and consequently provides an incentive for parties to support the lowest forecast possible in place of the most accurate forecast possible. If the modeling refinements produce a more accurate NPC forecast, then it should be approved even if it increases rates. CUB's proposal appears contrary to the Commission's prior determination that rate shock has no place in determining revenue requirement.

Q. CUB claims that the Commission should "avoid[] increasing the revenue requirement for items that are not *completely necessary* for providing service to customers in 2023[.]"[10] Are any of the costs included in the TAM forecast unnecessary for providing safe and reliable service in 2023?

A. No.

[9] CUB/100, Jenks/6.
[10] CUB/100, Jenks/3 (emphasis in original).

IV. REPLY TO AWEC

A. PTCs

Q. Like Staff, AWEC also recommends an adjustment to reflect a one-tenth of a cent increase in the PTC rate.[11] How do you respond?

A. Please see my response to Staff above on this same issue.

B. Utah Schedule 34

Q. Please describe AWEC's proposed adjustment related to Utah Schedule 34.

A. AWEC recommends that both the load and demand related to a Utah large load customer taking service under Utah Electric Service Schedule No. 34 (Utah Schedule 34) be included in the jurisdictional allocation factors used in the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) to assign costs among PacifiCorp's states.[12] More specifically, AWEC incorrectly claims that the Company's current treatment for this Utah Schedule 34 customer is not consistent with the 2020 Protocol, which requires all load PacifiCorp serves to be included in the load based dynamic allocation factors. AWEC's calculated impact of this recommendation to revise allocation factors would decrease Oregon-allocated NPC by $5.1 million.

Q. Does the Company agree with AWEC's recommendation that both the entire load and demand associated with the Utah Schedule 34 customer should be included in jurisdictional allocation factors?

A. No. To understand why, it is important to provide some background on the specific

[11] AWEC/100, Mullins/3.
[12] AWEC/100, Mullins/4-10.

contract that is the subject of AWEC's proposed adjustment. The Company entered into a contract where a new Utah large load customer brought new load and new offsetting renewable resources. The customer contract was entered into pursuant to Utah Schedule 34, which is a Utah program created by Utah Code section 54-17-806 that allows a qualifying customer to offset their load with renewable resources.

For purposes of calculating jurisdictional allocation factors, the new renewable resource generation and new customer load under Utah Schedule 34 are treated on a net basis. Any costs that could arise from this agreement are situs assigned to Utah and have no impact on Oregon customers.

Q. Please explain how Oregon customers are not impacted?

A. When calculating jurisdictional allocation factors, there are two scenarios that could arise from Utah Schedule 34; the customer load requirement is fully offset by the renewable generation, or the customer load requirement is greater than the renewable resource generation.

First, I would like to discuss the treatment of jurisdictional allocation factors and NPC as it relates to the scenario in which the Utah Schedule 34 customer is fully offset by the renewable generation. As described earlier in my testimony, the Company calculates jurisdictional allocation factors on a net basis, meaning the customer load is removed from jurisdictional allocation factors because the associated renewable generation sufficiently covered its load. Under this scenario, there is no customer load under Utah Schedule 34 that is being served by the Company. Therefore, under the 2020 Protocol, there is no load to be included for jurisdictional allocation purposes. The Company then removes from NPC all costs associated with the associated renewable generation, matching the costs and the benefits of this agreement. The result of this treatment is that Oregon customers are held harmless, they are not bearing any cost associated with the Utah load or any resources used to serve this load.

Under the second scenario the Utah Schedule 34 customer load exceeds the renewable generation. In this scenario, the Company continues to treat jurisdictional allocation factors on a net basis. The Company would remove any load served by the renewable generation from jurisdictional allocation factors. Any remaining load that is now served by the PacifiCorp system is included in jurisdictional allocation factors. Like the first scenario, the Company continues to remove from NPC any costs associated the renewable generation. The excess load served by the PacifiCorp system continues to remain in the total-company NPC with the Utah jurisdiction assuming a higher allocation of all costs due to the inclusion of the net load in jurisdictional allocation factors.

Q. AWEC claims that the Utah Schedule 34 customer relies on PacifiCorp's generation fleet to integrate the renewable resources it brought to the Company and that the customer does not pay the costs of transmission service to deliver its dedicated resources to its load.[99] How do you respond?

A. I disagree with this assertion. In the ongoing Oregon General Rate Case, docket UE 399, the Company made an adjustment to remove from Oregon wheeling expenses associated with this customer and assign those expenses directly to Utah. This treatment was done specifically to account for this customer's reliance on the transmission system and ensure other jurisdictions remain unimpacted by Utah Schedule 34.

Q. AWEC claims that the Utah Schedule 34 contract is a "Special Contract" as that term is defined in the 2020 Protocol and therefore the customer load must be included as Utah load in the Load-Based Dynamic Allocation Factors.[13] How do you respond?

A. AWEC has misapplied the 2020 Protocol. Appendix A of the 2020 Protocol defines "Special Contract" as "a contract entered into between PacifiCorp and one of its retail customers with prices, terms, and conditions different from otherwise-applicable tariff rates. Special Contract may provide for a value consideration to the customer to reflect attributes of Customer Ancillary Service Contracts."[14] A Utah Schedule 34 contract clearly does not meet the definition of a "Special Contract" as Utah Schedule 34 is an available service to qualifying customers provided for through PacifiCorp's electric service tariffs for the state of Utah.

Q. Please explain the circumstances of the Utah Schedule 34 contract in question.

A. The circumstances related to this specific Utah Schedule 34 contract are unique because the customer brought new load *and* new renewable resources to serve that load. Accordingly, the Company does include the customer load in the Utah jurisdiction for purposes the Load-Based Dynamic Allocation Factors when the renewable resource generation is not sufficient to meet the customer load. Absent

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[13] AWEC/100, Mullins/5.
[14] *In the Matter of the Application of PacifiCorp for an Investigation into Inter-Jurisdictional Issues*, Docket No. UM 1050, PAC/101, Appendix A at 7-8 (Dec. 3, 2019).

this net treatment, the Utah customer may not have entered into a contract with the Company and would not have built their facility in Utah.

Q. What provision of the 2020 Protocol is applicable to this scenario?

A. Section 5.8 of the 2020 Protocol, State-Specific Initiatives, which states the "[c]osts and benefits resulting from a state-specific initiative" are "allocated and assigned on a situs basis to the State adopting the initiative."

Q. Does the TAM forecast include regulation reserves for the Utah Schedule 34 customer's renewable resources?[15]

A. No. The regulation reserve obligations incurred by the Company due to the integration of system renewable resources do not include the Utah Schedule 34 customer's renewable resources as part of its calculation. More specifically, in the TAM, regulation reserves are not set aside for integration of the customer's renewable resources.

Q. AWEC also criticizes the Company for not following Oregon's resource procurement process for the renewable resources used to serve the Utah Schedule 34 customer.[16] How do you respond to this concern?

A. First, the resources that are dedicated to serve the Utah Schedule 34 customer were brought to the Company by the customer as a condition for that customer taking service from the Company and constructing its facility in Utah.

[15] AWEC/100, Mullins/7.
[16] AWEC/100, Mullins/8.

Second, the structure of the transaction with the Utah Schedule 34 customer and the proper application of the 2020 Protocol, holds Oregon customers harmless and assigns the costs and benefits of Utah Schedule 34 to the customer.

Third, it is my understanding that the Commission has granted waivers of its competitive bidding rules under comparable circumstances.[17]

Q. Has AWEC made this same argument to other commissions?

A. Yes. It is my understanding that AWEC made the same argument to the Idaho Public Utilities Commission (IPUC) in the Company's most recent Energy Cost Adjustment Mechanism filing (IPUC Case No. PAC-E-22-05).

Q. Did the IPUC accept AWEC's adjustment?

A. No. The IPUC rejected AWEC's argument in Order No. 35419 on May 26, 2022.

C. Utah Demand Side Management

Q. AWEC recommends removal of the Utah demand-side management adjustment from the calculation of the Load-Based Dynamic Allocation Factors, which reduces NPC by $1.6 million.[18] What is the basis for AWEC's recommendation?

A. For purposes of allocation under the 2020 Protocol, the Company adjusted Utah's load to account for demand-side management programs. AWEC claims that this adjustment should be reversed because, according to AWEC, "To the extent that the Coincident Peaks are being reduced by Utah's demand-side management programs, those reductions would have otherwise already been considered in the Utah's load forecast."[19]

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[17] *See, e.g., In re Idaho Power Company Application for Waiver*, Docket No. UM 2226, Order No. 22-082 (Mar. 11, 2022).
[18] AWEC/100, Mullins/11.
[19] AWEC/100, Mullins/11.

Q. Is AWEC's recommendation reasonable?

A. No. AWEC's adjustment is based on an incorrect understanding of how the Company treats demand-side management programs under the 2020 Protocol. The adjustments proposed by the Company for calculating Load-Based Dynamic Allocation Factors are for Class 1 demand-side management (Demand Response) programs. When the Company produces its peak forecasts, historical Class 1 demand-side management is added into the historical jurisdictional peak loads to produce an uncurtailed peak forecast. Therefore, the Company then adjusts the peak forecast downward to account for the Class 1 demand-side management programs when calculating jurisdictional allocation factors, a treatment consistent with Section 3.1.2.1 of the 2020 Protocol, as AWEC concedes.[20] AWEC's adjustment erroneously assumes that the initial peak forecast includes curtailed generation consistent with the Class 1 demand-side management programs. Because AWEC has provided no evidence that the peak forecast incorrectly accounted for Utah demand-side management programs, its adjustment should be rejected.

[20] AWEC/100, Mullins/10.

D. PSCo Contract

Q. AWEC claims that a new sales agreement with PSCo is uneconomic and should be found imprudent and repriced, which would result in a $3.6 million reduction to Oregon-allocated NPC.[21] How do you respond

A. The Company disagrees that the new contract is imprudent. AWEC's simplistic comparison of the contract price to the Company's official forward price curve (OFPC) ignores the larger context of the agreement.

Q. Please explain why the PSCo agreement.

A. [redacted]

[21] AWEC/100, Mullins/19-20.

Q. Why is simply comparing the PSCo agreement to the OFPC inadequate?

A. [redacted]

E. Northwest Pipeline Tax Reform Refund

Q. AWEC recommends the impact of the tax reform refund that is being addressed in Northwest Pipeline's upcoming FERC rate case be included as a reduction to NPC in this case.[22] How do you respond?

A. Northwest Pipeline is currently undergoing negotiations in anticipation of filing a rate case at FERC. Any changes to the Northwest Pipeline's tariff rate publicly available at the time of the final TAM update will be included.

[22] AWEC/100, Mullins/22-23.

V. REPLY TO CALPINE

Q. Calpine recommends that going forward PacifiCorp be required to adhere to the schedule for filing the Schedule 296 sample calculation as approved in docket UE 374; that is, the sample calculation with supporting workpapers should be provided within 30 days after the filing of the TAM.[23] How do you respond?

A. PacifiCorp anticipates that this sample calculation will be provided on the 30-day schedule in future TAM proceedings. PacifiCorp required additional time to prepare the input files for the Aurora model in order to complete the required sample calculation for this year's TAM.

VI. OTR

Q. On April 5, 2022, the United States Environmental Protection Agency proposed new rules on cross-state air pollution (Ozone Transport Rule).[24] Please provide some background on this rule and its possible impact on 2023 NPC and the TAM?

A. The OTR is also referred to as the Good Neighbor Rule or Cross-State Air Pollution Rule and focuses on reductions of nitrogen oxides (NO_x) which are precursors to ozone formation. Previously, OTR cover 22 states, but the OTR will now cover 26 states with four states, Wyoming, Utah, Nevada, and California being included for the first time. Beginning in 2023, trading allowances and emissions budgets are expected to be set to achieve NO_x reductions. It is still a proposed rule but the trading allowances and emissions budgets are expected to have an impact to NPC. As more

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[23] Calpine/100, Higgins/7.
[24] 87 Fed. Reg. 20036 (April 5, 2022).

information becomes available, PacifiCorp anticipates including the impacts of OTR in the final TAM update.

Q. Does this conclude your reply testimony?

A. Yes.

REDACTED
Docket No. UE 400
Exhibit PAC/600
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Ramon J. Mitchell

June 2022

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Ramon J. Mitchell. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Briefly describe your education and professional experience.

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have worked on production cost models in the context of net power costs, on market policy and analytics in the context of regional markets and on balancing authority operations and the energy imbalance market in the context of transmission grid operations. Prior to my current role I was employed by Portland General Electric in 2021 as a market bidding strategist. In my current role I am responsible for leading and overseeing all modeling efforts associated with the Company's net power costs and various other regulatory filings.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony before the Public Utility Commission of Oregon (Commission).

II. PURPOSE OF TESTIMONY

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

A. My testimony has two sections. First, I provide a Transition Adjustment Mechanism (TAM) update (Reply Update), as allowed under TAM Guidelines adopted by the

Commission in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363.[1] In the Reply Update, I explain the reasonableness of the Company's updated Oregon net power costs (NPC) of $1.775 billion (total-company) for the test period of the 12 months ending December 31, 2023.[2] This results in a rate increase of $24.3 million, Oregon-allocated, compared to the 2023 TAM initial filing (Initial Filing), for a total TAM increase of $94.3 million, Oregon-allocated. I provide corrections and contract, fuel, and forward price curve updates to the Company's Initial Filing.

Second, I respond to the opening testimony of Moya Enright, Heather Cohen, Curtis Dlouhy, Madison Bolton, Brian Fjeldheim, Steve Storm, and Rose Anderson, filed on behalf of Staff, Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB), Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC), and Ed Burgess, filed on behalf of the Sierra Club.

Q. Please summarize your testimony.

A. I demonstrate the reasonableness of PacifiCorp's NPC in the 2023 TAM through the following points:

- The Company's proposed modeling refinement to the Day-Ahead and Real-Time (DA/RT) adjustment improves the accuracy of the TAM forecast. The Company's refinement to the DA/RT price adjustment relies on a percentage, rather than a fixed amount, to adjust the hourly prices for purchases and sales.

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[1] *In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 10 (July 16, 2009); *In the Matter of PacifiCorp's 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 (Oct. 30, 2009); *In the Matter of PacifiCorp's 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 (Sept. 16, 2010).
[2] Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis.

Using a percentage more accurately reflects price variability throughout the day and is more consistent with historical data than the use of a constant dollar adjustment in all hours. Staff's proposed modification to the DA/RT adjustment, if adopted, would create inflated levels of intra-trading-hub arbitrage sales which are not achievable in actual operations and is unnecessary given that the DA/RT adjustment itself captures the historical arbitrage opportunities that exist in actual operations.

- The Commission should approve decreased market capacity limits (market caps) based on the "average of averages" methodology. The current methodology over-forecasts off-system sales volumes, which creates modeled revenues that decrease NPC but that are not achievable in actual operations. By reducing market caps, the Company will forecast off-system sales volumes that are more consistent with historical and expected market opportunities. Reducing market caps is particularly critical now because there is an unmistakable trend toward lower off-system sales volumes, and it is extremely unlikely that the Company could ever achieve the level of off-system sales volumes allowed by the current use of the "third-quartile of averages" market cap methodology.
- The Company's updated coal unit economic cycling study confirmed prior studies and prior TAM NPC reports demonstrating there are little to no customer savings associated with economic cycling. The Company's modeling appropriately accounted for reliability, to the extent possible in a production cost model, and considered wholesale market opportunities, consistent with Staff's recommendation in the 2022 TAM.

- The Company's use of Aurora has resolved prior disputes around minimum take modeling because Aurora can accept multiple tiered coal prices. The Company's provision of historical data was thorough and consistent with the Commission's direction in the 2022 TAM.
- The Company agrees to modify the forecasted Energy Imbalance Market (EIM) benefits consistent with Staff's recommendation.
- The Company's Qualifying Facility (QF) generation forecast is reasonable and should not be adjusted. Historical analysis demonstrates that the QF forecast is more accurate than the overall generation forecast and Staff's selective adjustment should be rejected, just as the Commission rejected it in the 2022 TAM.
- The Commission should approve the use of a planned outage schedule, rather than a historical average, because it is more accurate and is consistent with the NPC forecasting methodology used by other utilities.
- The Company's modeling reasonably accounted for reduced thermal generation during summer months and more accurately reflects actual operations.
- The Company should not have to perform backcasting analysis to validate the accuracy of the Aurora model, which is a third-party model that is widely used in the industry, including by another Oregon Commission-regulated utility.
- The Company has corrected the non-firm wheeling error identified by AWEC but has not accepted AWEC's adjustment to short-term transmission because it is based on an incorrect understanding of the Company's transactions.
- The level of emergency purchases is reasonable in the Aurora forecast and represents a small fraction of the overall generation modeled in the TAM.

- The Company's coal dispatch modeling based on incremental pricing is consistent with the methodology approved by the Commission in the 2022 TAM and consistent with well-established economic principles. The Company's minimum take modeling is also consistent with the methodology approved in the 2022 TAM and accurately reflects coal market realities that must be taken into account when dispatching coal plants.

III. TAM REPLY UPDATE

Q. How has the Company's net power costs recommendation changed from the Initial Filing?

A. Total-company NPC have increased by $91.9 million (total-company) compared to the forecast included with the Initial Filing, from $1.683 billion (total-company) to $1.775 billion (total-company). This change is primarily driven by sharp increases in the official forward price curve (OFPC). Between the December 2021 OFPC used in the Initial Filing and the March 2022 OFPC used in the Reply Update, the OFPC has increased approximately 123 percent. OFPC price increases since the Initial Filing are illustrated below in Confidential Figure 1. Additional details on the OFPC impacts to the NPC forecast are provided later in my testimony. Exhibit PAC/601 tabulates the modeling steps which show, in finer granularity, the change in NPC from the Initial Filing to this Reply Update. Exhibit PAC/602 shows that PacifiCorp's Reply Update proposes a rate increase of $94.3 million, Oregon-allocated. Details of total-company NPC for this Reply Update are provided in Exhibit PAC/603.

Confidential Figure 1

[redacted]

Q. Please explain the changes reflected in your revised NPC request.

A. First, consistent with the TAM Guidelines the Company made routine updates to the Initial Filing and updated the Company's proposed NPC with (1) the most recent OFPC and short-term firm transactions, (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts, and (3) EIM benefits based on most recent actual EIM benefit information as well as the updated OFPC. Finally, corrections to the regulation reserve requirements, Utah solar adjustments, wheeling costs and short-term transmission transactions have been included in this update.

Additionally, the Company made three changes to the NPC forecast in response to parties' testimony. The first is regarding the EIM benefit forecast.

Staff's testimony included a proposal to update the methodology for the [redacted],[3] which the Company accepted. The second is a set of proposed updates to the Company's [redacted]. My testimony addresses this topic in greater detail below.

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

A. Table 1 below has details regarding the individual cost categories that accumulate to the change in the total NPC forecast (total-company).

Table 1

Net Power Cost Reconciliation		
	($ millions)	**$/MWh**
OR TAM 2023 Initial Filing	**$1,684**	**$27.25**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(39.0)	
Purchased Power Expense	53.7	
Coal Fuel Expense	45.6	
Natural Gas Fuel Expense	37.0	
Wheeling and Other Expense	(5.5)	
Total Increase/(Decrease) to NPC	**91.9**	
OR TAM 2023 Reply Filing	**$1,776**	**$28.73**

There is an increase in forecasted wholesale sales revenue of $39 million, the benefits of which are offset by an increase in purchased power expense of approximately $53.7 million. Coal fuel expense and natural gas fuel expense have increased by $45.6 million and $37 million, respectively. Finally, wheeling, and other expenses have decreased by $5.5 million.

[3] Staff/800, Dlouhy/19

Q. Please explain in further detail how the large OFPC changes in power prices and gas prices have impacted NPC.

A. On a dollar basis, purchased power expense has increased by six percent and natural gas fuel expense has increased by 11 percent, however, on a megawatt-hour (MWh) basis, the volume of purchased power has *decreased* by four percent and natural gas generation has *decreased* by 13 percent. Purchased power expense and natural gas fuel expense have increased even though the associated energy/generation has decreased due to the overwhelming impact of the OFPC increases. As prices for purchased power and natural gas fuel have increased, the associated energy has been displaced by other sources of Company generation.

Q. What lower cost generation has replaced natural gas and purchased power to dampen the effects of the OFPC increase on NPC?

A. Coal generation; although market prices for purchased power and natural gas fuel prices have increased, the Company's coal fuel is mostly covered by coal supply agreements (CSAs) and prices have remained relatively constant. Consequently, coal generation has increased by eight percent, offsetting the decrease in purchased power and natural gas generation. The relatively improved economics of the Company's coal fuel prices have also contributed to a modest rise in wholesale sales and its associated revenue. Table 2 is a companion to Table 1 and tabulates the line-by-line MWh changes to net system load (total-company).

Table 2

	MWh	$/MWh
OR TAM 2023 Initial Filing	61,802,663	$27.25
MWh Change to Net System Load:		
Wholesale Sales *Increase*	**133,066**	
Purchased Power *Decrease*	**(788,652)**	
Coal Generation *Increase*	**2,355,925**	
Natural Gas Generation *Decrease*	**(1,434,208)**	
Wheeling and Other	-	
Total MWh Change to Net System Load	**(0)**	
OR TAM 2023 Reply Filing	61,802,663	$28.73

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

A. The Reply Update includes the following corrections and updates (the NPC impacts are based on the Initial Filing):

- **Regulation Reserve Requirement** – The Company corrected a data input error in the calculation of the regulation reserve requirement that was included in the Initial Filing. This correction decreased the level of reserves held in both PacifiCorp West (PACW) and PACE. The impact was a decrease in total-company NPC of $16.6 million.
- **Utah Solar Adjustment** – The Company corrected a miscalculation of the Utah Solar Adjustment that was included in the initial filing. The change was the correction of load associated with Utah Schedule 34 and the resources that are contractually obligated to serve the load. The impact was a decrease in total-company NPC of $11.4 million.
- **OFPC** – The Company updated the OFPC from December 31, 2021, to March 31, 2022. On average, market prices for electricity increased by

approximately 115 percent. Market prices for natural gas increased, on average, by approximately 131 percent. This OFPC update increases total-company NPC by $80.1 million.

- **Short-Term Firm Transactions and Gas Hedges** – Short-term sales and purchase transactions for electricity and natural gas were also updated through May 1, 2022. Additionally, gas hedges that reflect the Company's stance were updated. These updates decrease total-company NPC by approximately $2.5 million.
- **QFs and Long-Term Contracts**– The Company has included QF and Long-Term contract updates through May 1, 2022. Delays in the commercial operation dates (COD) of certain solar facilities removed over [redacted] that were scheduled to come onto the system in 2023. These updates increase total-company NPC by approximately $43.3 million.
- **Coal Costs** – The Company has updated coal fuel costs to reflect changes in prices and volumes since the Initial Filing. Company witness James Owen provides additional detail on the Reply Update in his reply testimony. The update decreases total-company NPC by approximately $8.1 million.
- **Wheeling –** The Company has updated wheeling expenses to reflect the corrections made. The update decreases total-company NPC by approximately $5.5 million.
- **Short-Term Transmission Links –** A correction was made to the short-term transmission capacities. The capacities accurately reflect the historical short-term

transmission capacities. The update decreases total-company NPC by approximately $2.4 million.

- **EIM Inter-Regional Transfer Benefits and GHG Benefits** – PacifiCorp's estimated EIM benefits for 2023 have been updated to include the most recent information through April 2022. On a total-company basis, the expected inter-regional transfer benefits are [redacted], an increase of [redacted]; the total-company forecast GHG benefits are [redacted], an increase of [redacted]. This update decreases total-company NPC by approximately [redacted].
- **Washington State's Cap and Trade Program** – As a result of Washington State's new cap and trade law, the Climate Commitment Act (CCA),[4] discussed further in the testimony of Company witness Shahumyan, the dispatch cost for the Chehalis gas plant has increased. This update increases total-company NPC by approximately $19.9 million.

Q. Please explain how PacifiCorp incorporated the impact of Washington State's cap and trade law in the NPC forecast?

A. The requirements of the CCA and the Chehalis price adder are described in greater detail in the testimony of Company witness Shahumyan. To incorporate these costs into the NPC forecast, PacifiCorp increased the dispatch cost of the Chehalis plant by approximately [redacted], derived from forward prices of California Carbon Allowances on the Intercontinental Exchange of $30.45 per metric ton of carbon dioxide equivalent.

[4] RCW 70A.65.005 *et seq.*

IV. REPLY TO STAFF

A. DA/RT Adjustment

Q. Please describe the DA/RT adjustment.

A. PacifiCorp incurs system balancing costs that are not reflected in the Company's OFPC or modeled in Aurora. To address this deficiency, in the 2016 TAM, the Company proposed the DA/RT adjustment to more accurately model system balancing transaction prices and volumes.

In the 2016 TAM, Staff, CUB, and ICNU (the predecessor to AWEC) objected to the DA/RT adjustment. The Commission, however, rejected their arguments and approved the adjustment after concluding that it more accurately reflected the costs of system balancing transactions in the Company's NPC forecast.[5]

In the 2017 TAM, Staff, CUB, and ICNU again objected. The Commission again affirmed the DA/RT adjustment, concluding that it "reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs."[6]

In the 2018 TAM, Staff, CUB, and AWEC again objected to the DA/RT adjustment. The Commission again affirmed the adjustment but adopted a modification to use only post-EIM years.[7]

The Company included the DA/RT adjustment in the 2019, 2020, 2021, and 2022 TAMs without modification.

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[5] *In re PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015).
[6] *In re PacifiCorp, dba Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016).
[7] *In re PacifiCorp, dba Pac. Power 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 5-9 (Nov. 1, 2017).

Q. How has the Company refined the DA/RT adjustment in this case to reflect system balancing costs more accurately?

A. Fundamentally, the DA/RT adjustment includes separate prices for forecasted system balancing sales and separate prices for forecasted system balancing purchases that better reflect the prices available to the Company when it transacts in the markets. These prices account for the historical price differences between the Company's purchases and sales as compared to the monthly average market prices.

The price component of the DA/RT adjustment has historically been a flat dollar amount that is added to or subtracted from the hourly scaled prices in the OFPC. In this case, the Company further refined the adjustment so that instead of using a uniform flat dollar adjustment, the DA/RT adjustment uses a percentage that more accurately accounts for the intra-month price variability.

Q. Staff testifies that it was "hopeful that the change to AURORA would eliminate the need for DA/RT as it was a GRID deficiency, but the Company has testified that there is no AURORA feature that would address" the differences between purchase and sales prices realized in actual operations.[8] Why is that?

A. As noted above, the basis of the DA/RT adjustment is founded in the historical price differences between the Company's purchases and sales as compared to the monthly average market prices. The fact that there are historical price differences between the Company's purchases and sales as compared to the monthly average market prices is agnostic to the model used to forecast Company purchases and sales. Therefore, the

[8] Staff/200, Cohen/9.

transition to Aurora has not resolved the basis for the DA/RT adjustment, which the Company has used consistently since the 2016 TAM.

Q. Does Staff object to the DA/RT adjustment in this case?

A. Yes. Staff objects both to the proposed refinement to the DA/RT adjustment and to the price component of the adjustment that has been included in the TAM for the last seven years.

Q. Did Staff quantify its proposed adjustment?

A. Not entirely. Removing the Company's proposed refinement to the DA/RT adjustment reduces Oregon-allocated NPC by $5.2 million. Staff did not quantify the impact of eliminating the "price component" of the DA/RT adjustment. Staff recommends "removing the biased DA/RT price component altogether."[9] However, it is unclear to the Company whether Staff is proposing to remove the DA/RT adjustment in its entirety, or to remove the pricing logic which prevents unrealistic model arbitrage, as I discuss later in my testimony.

Q. What is the basis for Staff's objection to the refinement proposed in this case?

A. Staff claims that the Company has not provided any evidence that using a percentage adjustment better captures intra-month price variability.[10]

Q. How does a percentage adjustment better capture intra-month price variability?

A. In the testimony below, I provide analysis on the drivers of the DA/RT adjustment, including a discussion of historical hourly scaled monthly average market prices as compared to historical hourly scaled Company purchases and associated purchase prices across four years of historical data from 2018 to 2021. This analysis shows

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[9] Staff/200, Cohen/15.
[10] Staff/200, Cohen/14.

that the refinement proposed by the Company more accurately accounts for intra-month price variability in the context of the historical data.

Q. Why focus on Company purchases instead of Company sales?

A. Across the historical period, the total net peak expense incurred from Company purchases is approximately 4.9 times greater than the total net peak revenues gained from Company sales. Confidential Figure 2 provides an illustration of this along with the average 4-year historical hourly shape of purchases, sales, purchase expenses and sales revenues. This data, along with the observation that throughout the historical period the Company is a net purchaser (importer) on a dollar and volume basis and that Aurora has no market caps on purchases highlights the outsized importance of purchased power and its attendant costs.

Confidential Figure 2

[redacted]

Q. What does the historical data show when comparing market prices to the Company's purchases?

A. Confidential Figure 3 uses data from 2018 to 2021 to create two curves—one illustrating hourly scaled average market prices and one illustrating hourly scaled average Company purchase prices. The difference between the curves is an illustration of the DA/RT adjustment. The concept of intra-month price variability is exhibited by the change in price levels across the day for the hourly scaled average market prices as compared to the hourly scaled average Company purchase prices.

This price variability is set forth numerically in Confidential Table 3, which shows the numeric difference between the two curves.

Confidential Figure 3

[redacted]

Confidential Table 3

Hour Ending	Historical DA/RT Adjustment
1	[redacted]
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Q. Why do you refer to the variability as "intra-month" when the data appears to focus on variability within a day?

A. It is important to recall that the OFPC uses monthly prices, which are then scaled down to hourly prices. So intra-month price variability is exhibited as hourly price variability within each day of the month. In my testimony above, this intra-month price variability is presented as average hourly price variability across the four-year historical period for the average day.

Q. The DA/RT adjustment has historically been a flat dollar amount applied to the purchase and sales price. Does the historical data support this approach?

A. No. The historical data in Confidential Figure 3 and Confidential Table 3 shows intra-month variability in the DA/RT adjustment (i.e., the variability between the hourly scaled average market prices and the hourly scaled average Company purchase prices) is not constant across the day; the difference is generally greater as the price increases. If historical market prices supported, the DA/RT adjustment as a flat dollar amount then the historical values in Confidential Table 3 would not exhibit variability across the day but rather show consistency.

Confidential Figure 4 illustrates this variability in the historical DA/RT adjustment as compared to an illustration of a hypothetical flat adder bifurcated into heavy load hours (HLH) and light load hours (LLH).

Confidential Figure 4

[redacted]

Q. Is Confidential Figure 4 a visual of historical market price curves in comparison to a flat DA/RT adjustment?

A. No. Confidential Figure 4 is a visual of what the historical DA/RT adjustment is, based solely on the historical relationship between actual market prices and actual Company purchases along with a comparison to a hypothetical flat adder that is separated into HLH and LLH components. That is to say, Confidential Figure 4 is a visual of Confidential Table 3 along with a comparison to a hypothetical flat adder that is separated into HLH and LLH components. Confidential Figure 4 is not a visual of a market price curve, even though it looks similar.

Q. Does the historical data support the usage of a percentage adder to more accurately account for intra-month price variability?

A. Yes. As illustrated in Confidential Figure 3 and in Confidential Figure 4, as the historical average market price increases, the spread between the historical average market price and the historical average buy price increases as well. This suggests that a percentage adder is more suitable for capturing the historical interplay between monthly average market prices and Company purchase prices. As illustrated in Confidential Table 3, the historical data definitively does not suggest that a flat adder is appropriate for capturing this intra-month dynamic. This means that the Company's refinement to the DA/RT adjustment is a more accurate representation of the difference between average prices and the Company's transaction prices. Because the purpose of the DA/RT is to reflect this difference, the Company's refinement is consistent with the Commission's rationale for adopting the DA/RT adjustment in the 2016 TAM and repeatedly approving its use in the TAM forecast for the last seven years.

Q. What is the basis for Staff's objection to the underlying framework of the DA/RT adjustment as it has been approved and implemented since the 2016 TAM?

A. Staff claims that the DA/RT adjustment improperly creates "artificial losses" for the Company that are then used to increase forecasted NPC.[11] As Staff explains, "if PAC's buy price is lower than its sale price, [the DA/RT adjustment] calculates an amount that creates an artificial loss for the Company."[12] Staff claims that this "inherent bias in the DA/RT adder has not been correct in Aurora" and therefore recommends removing the "inherent bias" in the price component of the DA/RT adjustment.[13]

Q. Do you agree that the DA/RT adjustment improperly creates artificial losses?

A. No. The feature of the DA/RT adjustment Staff disputes has been a critical component of the DA/RT since it was first adopted by the Commission in the 2016 TAM. Without the adjustment that Staff disputes, the DA/RT adjustment could result in a scenario where the buy price at a particular hub is lower than the sales price at the same hub. If the inputs to Aurora for a single market showed a purchase price that was less than the sales price, then Aurora would buy and sell arbitrarily (arbitrage) large volumes of power under this situation, but in reality, the volumes in question would be very limited. In the event that this rare situation occurred in reality, all rational market participants would take advantage of this free profit arbitrage opportunity until market prices reached equilibrium and the purchase price

[11] Staff/200, Cohen/11.
[12] Staff/200, Cohen/11.
[13] Staff/200, Cohen/14-15.

was greater than or equal to the sales price. Within the Aurora model no equilibrium can ever be reached, as increasing demand does not impact price.

Given the Aurora model's inability to handle this circumstance, when the average monthly sales price exceeds the monthly purchase price in the same market, a single price adjustment is used for both sales and purchases based on the volume-weighted average of the historical sales and purchases. This ensures the modeled price component of the DA/RT adjustment better reflects market reality.

Q. Can you provide a quantitative example demonstrating the consequences of Staff's recommendation?

A. Yes. For simplicity, assume that the DA/RT adjusted Mid-Columbia sales price is \$2.00 per MWh and the DA/RT adjusted purchase price at Mid-Columbia is \$1.00 per MWh for the same time period. If these are the price inputs in Aurora, then the model will purchase energy at Mid-Columbia for \$1.00 and sell that same energy at Mid-Columbia for \$2.00 creating a \$1.00 profit per MWh bought and sold. Because the model would require no generation to support its ability to arbitrage in this way, it would make this simultaneous purchase and sale repeatedly until it hit the market capacity on sales (market caps). This cycle of repeated arbitrage behavior does not reflect market realities and would lead to absurd results.

Q. How would the DA/RT adjustment be impacted if the price component was eliminated, as Staff recommends?

A. The price component of the DA/RT adjustment was integral to the Commission's repeated approval of the adjustment because it represents the market reality that the Company typically purchases energy when prices are high and sells energy when prices are low. Staff did not present any evidence that the underlying market dynamics are no longer present and therefore provides no basis for eliminating the price component of the DA/RT adjustment.

B. Market Capacity Limits

Q. As background, please explain why Aurora requires market caps.

A. Like GRID, Aurora operates with perfect foresight and assumes unlimited market depth and full liquidity for the markets in which PacifiCorp makes off-system sales, unless informed otherwise. Aurora would therefore allow unlimited off-system sales at every market at any time of the day or night—an assumption that is very different from PacifiCorp's actual, historical experience.

To more realistically model actual market conditions, PacifiCorp has included market caps for sales since it introduced the GRID model in 2002.[14]

Q. How were market caps first implemented in GRID?

A. PacifiCorp originally modeled market caps in graveyard hours only. In the 2012 TAM, docket UE 227, PacifiCorp refined its market caps to specify market depth for sales during all hours based on historical average sales from the most recent 48-month period for each trading hub, each month, segregated by HLH and LLH periods.[15] This refined approach, known as the "average of averages" method, allowed for additional sales and reduced NPC compared to PacifiCorp's original graveyard market caps. At PacifiCorp's suggestion, the Commission adopted the

[14] *In re PacifiCorp dba Pac. Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 3-4 (Oct. 29, 2012).
[15] *In re PacifiCorp, dba Pac. Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 21 (Nov. 4, 2011).

average-of-averages approach in docket UE 227 on a non-precedential basis to allow an opportunity for additional review.[16]

In the 2013 TAM, docket UE 245, ICNU and Staff argued for elimination of market caps, a position the Commission rejected:[17]

> As Pacific Power observes, market caps have always been part of GRID and neither Staff nor ICNU persuasively argue that GRID, as it currently exists, no longer needs market caps. Based upon the evidence presented in this proceeding, we conclude that some form of market caps continue to be needed in GRID as it is now constructed. [18]

At the same time, the Commission accepted Staff's and ICNU's argument that the average-of-averages market cap methodology "overstates expected NPC."[19] Thus, the Commission adopted Staff's "alternative recommendation that essentially split the difference between the company's approach and Staff's recommended no cap approach."[20] This alternative methodology, referred to as the "maximum-of-averages" approach, sets "market caps on the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[21]

Under the maximum-of-averages approach, the Company had to use the most extreme outlier cap value supported by the historical record for every other market hub, resulting in sales that consistently exceed historical averages. This approach

[16] Order No. 11-435 at 23.
[17] Order No. 12-409 at 5-8.
[18] Order No. 12-409 at 7.
[19] *In re PacifiCorp, dba Pac. Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 13-008 at 1-2 (Jan. 15, 2013) (denying motion for reconsideration).
[20] Order No. 13-008 at 1.
[21] Order No. 12-409 at 7-8.

contrasts with the average-of-averages method, which includes extreme outlier values in the four-year average but does not rely on them exclusively to set the market cap.

Q. What prompted PacifiCorp to recommend a change to market caps in the 2022 TAM?

A. In every PCAM filing since 2012, when it was first adopted, the Company's actual NPC data demonstrated that the Company has persistently under-recovered its NPC in Oregon rates, which indicated that an average of averages market caps would not "overstat[e] expected NPC." In PacifiCorp's 2020 General Rate Case, docket UE 374, PacifiCorp sought changes to its PCAM. In response, Staff filed testimony analyzing PacifiCorp's NPC under-recovery between 2017-2019, relying on PacifiCorp's past PCAM filings.[22] Referring to two market transaction types, purchases and sales, Staff concluded that only one--sales--was "largely inaccurate in the forecast."[23] Staff testified that a "gross over-estimation of the sales benefit" was "apparent in both the dollar and MWh metrics."[24]

In its final order in docket UE 374, the Commission invited PacifiCorp to propose modeling changes in the TAM to increase its NPC forecast accuracy specifically concerning off-system sales:

> The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast, just as it did in the 2016 TAM when it introduced the DA/RT mechanism to increase the volume and modeled cost of balancing transactions to increase GRID's balancing costs. PacifiCorp does not necessarily need to develop a complex new adjustment, but may be able to improve its forecast accuracy with straightforward inputs or limits. For example, Staff shows that PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a "gross over-

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

> estimation of the sales benefit." PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. [25]

Q. Did the Commission modify the market caps in the 2022 TAM?

A. Yes. In the 2022 TAM, PacifiCorp requested that the Commission modify the market caps to revert to the average of averages methodology. The Commission did not adopt the Company's recommendation but did modify the market caps using a Staff proposal that set the caps using the "third quartile of averages" method, which averages the two highest values of the four highest monthly sales at each hub.[26] This modification reduced the market caps relative to the maximum of averages methodology.

Q. Did the Commission make any specific findings in its 2022 TAM order?

A. Yes. Most importantly, the Commission found that the record "support[ed] PacifiCorp's position that GRID does over forecast off-system sales with the maximum of averages market caps" and that the "data alone supports PacifiCorp['s] argument that from a rate-setting perspective, the average of averages is reasonable as it most closely approximates the historical average over the last four years."[27] But the Commission also noted that the data from 2021 and 2022 showed that "GRID produced a lower volume of sales even with the maximum of averages market cap, and it is too soon to know if that adjustment will bring the forecast closer to actuals."[28]

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[25] *In re PacifiCorp, dba Pac. Power Request for a Gen. Rate Revision*, Docket No. UE 374, Order No. 20-473 at 130 (Dec. 18, 2020) (footnotes omitted).
[26] *In re PacifiCorp, dba Pac. Power 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 26 (Nov. 1, 2021).
[27] Order No. 21-379 at 27-28.
[28] Order No. 21-379 at 28.

The Commission also acknowledged the transition away from GRID and to Aurora and therefore clearly stated that its "findings on market caps [were limited] to the 2022 TAM only."[29]

Q. Please explain why PacifiCorp has again recommended use of the average of averages methodology for calculating the market caps in Aurora.

A. As noted above, Aurora is functionally the same as GRID in that it will transact in the market at unrealistic levels without a constraint, like market caps. Therefore, the Company has again recommended that the market caps be set using the average of averages approach.

Q. Is the average of averages methodology used to set the market caps used in PacifiCorp's other states?

A. Yes. Oregon is the only state that has adopted higher market caps and therefore using the average of averages market cap methodology will align the Company's NPC forecast in each jurisdiction.

Q. Have forecasted off-system sales continued to exceed actual off-system sales?

A. Yes. Below, in Confidential Table 4, is an updated table that the Company provided in response to Bench Request 4 in the 2022 TAM and that the Commission included in Order No. 21-379:

[29] Order No. 21-379 at 27.

Confidential Table 4

Year (Filing and Method)	Short-Term Sales (MWh) Actual	Forecast	(Below)/Above Forecast
2012	[redacted]		
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023 (Direct Third Quartile of Averages)			
2023 (Direct Average of Averages)			

Note: The actual values in Confidential Table 4 are net of bookouts, which are not included in the forecast.

Q. What additional information is shown in Confidential Table 4, relative to the data included in the record of the 2022 TAM?

A. First, forecasted off-system sales for 2021 were *nearly double* the actual off-system sales.

Second, forecasted off-system sales for 2022—which used the third quartile of averages methodology—are significantly higher than actual off-system sales volumes for the last eight years and only modestly below the 2021 forecast using the maximum of averages method

Third, even using the average of averages methodology for the 2023 forecast produces forecasted off-system sales that are higher than actual off-system sales for 2019, 2020, and 2021. As discussed in more detail below, this fact is particularly critical given that trends show a definitive decrease in market transactions.

Q. Has the excessive forecasted off-system sales contributed to the Company's under-recovery of NPC in Oregon?

A. Yes. Indeed, in PacifiCorp's last general rate case, both Staff and the Commission concluded that the over-forecast of off-system sales has contributed to the Company's under-recovery of NPC in Oregon.[30]

Q. What is the basis for Staff's recommendation that the Commission affirm the use of the third quartile of averages methodology?

A. Staff claims that the Company was "misleading" in Confidential Figure 2 in the direct testimony of Company witness Michael Wilding because the figure compared actual off-system sales volumes from 2019-2021 to forecasted off-system sales volumes from the 2022 and 2023 TAM filings but made "no attempt to directly compare" the average of averages and the third quartile of averages methodologies against one another.[31]

Q. How do you respond to Staff's allegation that the Company was misleading?

A. The Company disagrees. The direct testimony of Company witness Wilding explained that the third quartile of averages methodology created more off-system sales than occur in actual operations, which was demonstrated by comparing the forecasted off-system sales values using the third quartile of averages methodology in the 2022 and 2023 TAM forecasts to the actual sales volumes from 2019, 2020, and 2021. The results show that the TAM forecast is materially higher, which indicates that the market caps set using the third quartile of averages methodology is enabling Aurora to make more off-system sales than the Company can realize in actual

[30] Order No. 20-473 at 130.
[31] Staff/300, Dlouhy/9-10.

operations. Contrary to Staff's claims, there is nothing misleading in the description or presentation of data in Confidential Figure 2 in the direct testimony of Company witness Wilding. The fact that the data does not compare the two different methodologies for calculating market caps does not indicate that the data is misleading.

Q. Staff also claims that the Company was unresponsive to its discovery requests seeking a comparison of the average of averages and the third quartile of averages methodologies against one another.[32] Do you agree?

A. No. The Company was not "unresponsive." Rather, the Company explained that the specific analysis Staff requested was "extremely burdensome." In particular, Staff requested that the Company develop forecasted market sales for 2019-2021 using equivalent inputs in Aurora from those years and the third quartile of averages approach. The Company responded that producing the requested analysis was overly burdensome because the Company was not using Aurora in 2019-2021 and therefore it would have had to reformat and convert GRID input data from those years to create equivalent Aurora data. Building an Aurora database for those years would have taken months to complete. Given the difficulty of complying with Staff's request, particularly given the tight timelines inherent in the TAM, the Company could not provide the comparison requested.

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[32] Staff/300, Dlouhy/9-10.

Q. Staff claims that the Company was misleading because the data presented in Confidential Figures 3 and 4 in the direct testimony of Company witness Wilding "could be easily combined into a single graph but are separated."[33] Do you agree that it was "misleading" to include two graphs instead of one?

A. Not at all. For context, Confidential Figure 3 compared thermal generation in the 2022 TAM and 2023 TAM and Confidential Figure 4 compared thermal generation under the Company's proposed market cap compared to Staff's market cap methodology. Each graph correctly explained what information was presented. Staff did not claim that the information was incorrect or inaccurate and the fact that the Company chose to present it in a different way than Staff would have preferred does not make it misleading.

Q. Staff also claims that the Company was misleading because it suggested that using the third quartile of averages approach was contrary to Oregon state policy because it resulted in higher thermal generation in the NPC model.[34] Do you agree that it was "misleading" to make this connection?

A. No. Importantly, Staff does not dispute that using the third quartile of averages approach increases thermal generation to facilitate off-system sales. While it is true that the NPC forecast used in the TAM does not impact actual thermal generation, there is a disconnect if the Company's rates reflect greater thermal generation than occurs in actual operations. For example, it is Oregon policy that electric utilities meet increasing targets for reducing greenhouse gas emissions.[35] Requiring the

[33] Staff/300, Dlouhy/10.
[34] Staff/300, Dlouhy/10.
[35] ORS 469A.405.

Company to model an approach that is both inconsistent with actual operations and inconsistent with Oregon state policy is inappropriate.

I would also note that Staff has previously argued that the TAM forecast should act as a benchmark for actual operations, which is inconsistent with Staff's position here that the TAM forecast has no impact on actual operations and therefore does not need to be consistent with state energy policy.[36]

Q. Staff testifies that, "Unless the Company can provide some sort of direct comparison between past actual off-system sales and AURORA forecasted results, there will not be enough empirical evidence to justify a change to the market cap methodology in the 2023 TAM."[37] Do you agree that such a direct comparison is necessary?

A. No. As noted above, the third quartile of averages methodology creates more off-system sales than occur in actual operations and is therefore not accurately reflecting expected market conditions. The fact that the data does not compare different methodologies for calculating market caps does not invalidate these findings.

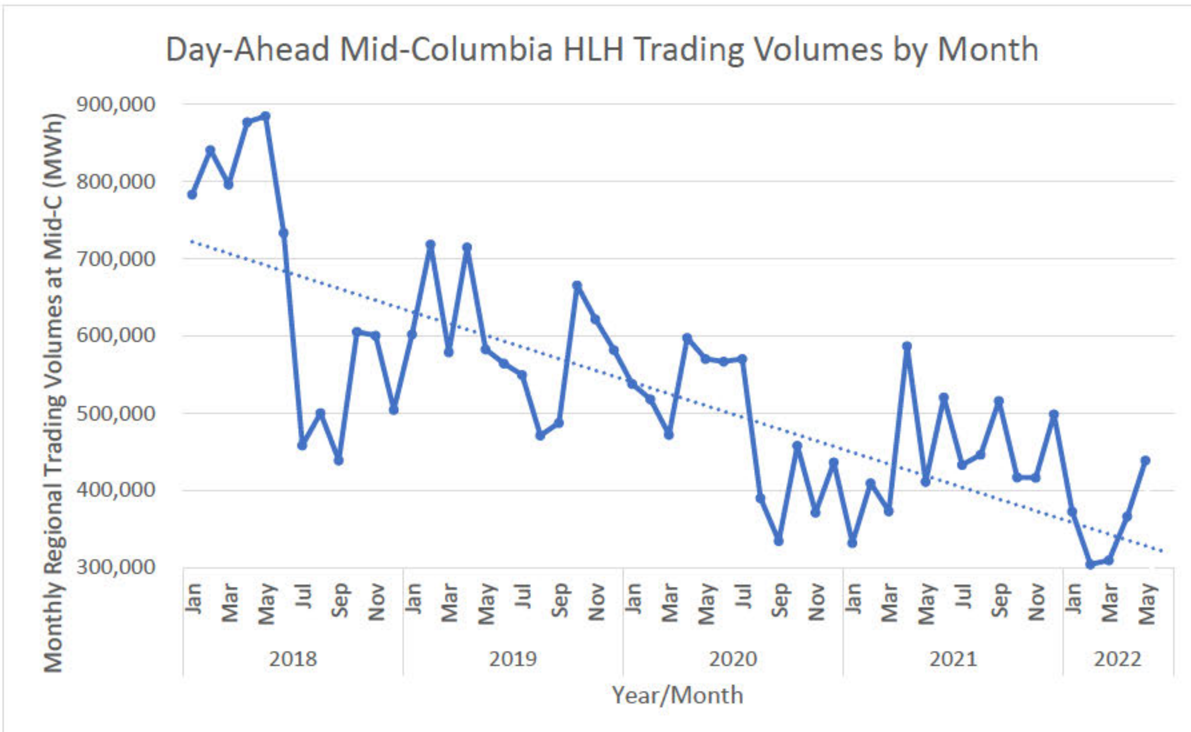
Q. What other empirical evidence justifies the Company's proposed change to the market cap methodology in the 2023 TAM?

A. The volume of transactions in regional wholesale markets has been steadily declining in recent years, which supports a lower market cap. This decline is evident by examining data from the Intercontinental Exchange (ICE), which is the primary platform used to trade energy on a day-ahead basis in the western interconnection.

[36] *See e.g.,* Docket No. UE 375, Staff/200, Enright/10.
[37] Staff/300, Dlouhy/13.

Data from ICE at the Mid-Columbia trading hub over the HLH show that trading volumes have been consistently trending downwards over the past four years, from 2018 to 2021. Because a trade requires two counterparties, a buyer and a seller, a decrease in trading volumes year over year implies lower market sales volumes year over year across the Mid-Columbia region. This ICE data is illustrated in Figure 5.

Figure 5



Q. How do the lower year over year sales volumes across the region compared to the Company's year over year sales volumes?

A. The Company's year over year sales volumes in the day-ahead bilateral markets exhibit the same diminishing trend. This trend is illustrated in Confidential Figure 6, which shows total-company sales data, as used to directly calculate the market caps in this TAM and in prior TAMs.

Confidential Figure 6

[redacted]

Q. How do the market caps relate to the Company's historical sale volumes?

A. They are the same thing, expressed in different units and averaged over time. Whereas Confidential Figure 6 shows a measure of total sales volume by month for the past four years, the market cap methodology will first calculate the average hourly sales volume by month, trading hub and HLH/LLH for the past four years and then, to derive the monthly market cap for 2023, average the four average hourly sales volumes by month (average of averages), or average the largest two average hourly sales volume by month (third quartile of averages). Therefore, Confidential Figure 6 shows the actual historical market caps, albeit at a different scale and aggregated. It is important to note that the MWh sales data underlying Confidential Figure 6 is the actual data used to calculate market caps in this TAM and in prior TAMs.

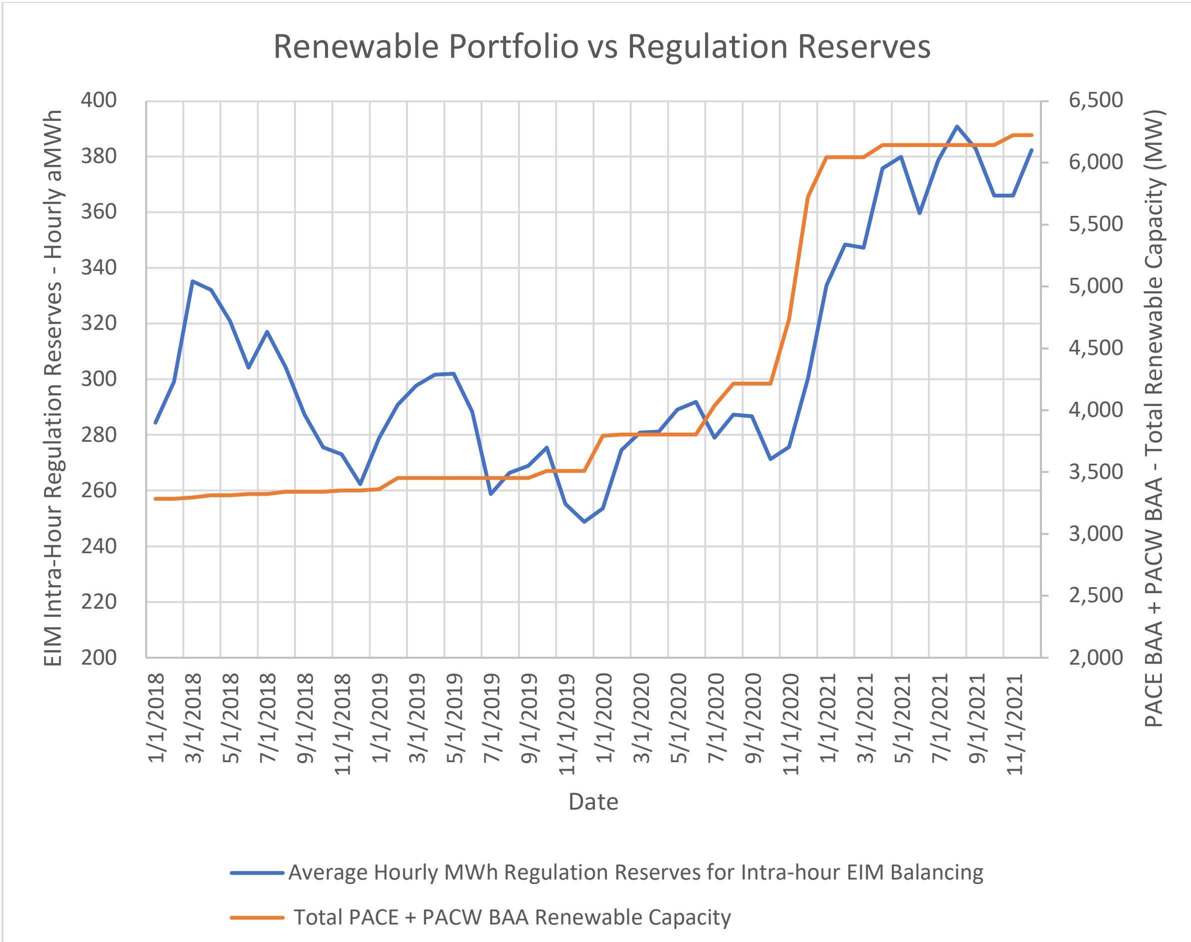
Q. Why have sales volumes been decreasing across the region, and similarly at the Company, in the day-ahead timeframe?

A. Market sales are supported by excess supply, and excess supply in this context is defined as the generation capacity remaining after all load and reserve obligations have been served. As excess supply decreases, market sales decrease. Diminishing excess supply in the region and in the Company is attributable to increased regulation reserves and the EIM.

Q. How do regulation reserves contribute to diminishing excess supply?

A. As entities across the region integrate ever increasing numbers of variable renewable resources into their portfolio, their regulation reserve obligations increase. This relationship is illustrated in Figure 7. As these reserve obligations increase, excess supply is diminished. This reduction in excess supply will naturally result in lower market sales in the day-ahead timeframe. The trend whereby variable renewable resources occupy a larger portion of entities' portfolios over time is one that will continue to increase well into and past 2023 due to various federal and state regulations. The drivers of regulation reserves are discussed in detail within the direct testimony of Company witness MacNeil.

Figure 7



Q. Are the regulation reserve numbers in Figure 7 representative of PacifiCorp's regulation reserve requirements in the direct testimony of Company witness MacNeil?

A. No. These numbers are the EIM's calculation of regulation reserves using errors in load, wind and solar forecasts made approximately 45 minutes before the operating moment (real-time) as compared to forecasts made approximately 10 minutes before real-time. PacifiCorp's regulation reserve requirements, subject to NERC standards, are calculated from errors in load, wind, solar and other non-dispatchable generation forecasts made approximately 107 minutes before real-time as compared to actuals (i.e., 0 minutes before real-time). As such, the trend is comparable but not the magnitude.

Q. How does the EIM contribute to diminishing excess supply?

A. With the emergence of the EIM, which now serves approximately 77 percent[38] of the demand for electricity in the western interconnection, EIM entities face additional opportunity costs that must be contemplated in the day-ahead timeframe. If an EIM entity finds itself with excess supply and the expected price in the EIM is greater than the prevailing price in the day-ahead time frame, then the entity may forego selling their excess supply into the day-ahead markets and instead set that excess supply aside for sale in the EIM. This naturally reduces market sales in the day-ahead timeframe.

Q. What about the hour-ahead bilateral market?

A. As it concerns regulation reserves, the associated obligation exists in the day-ahead timeframe as well as in the hour-ahead timeframe. Regulation reserve obligations diminish excess supply in both timeframes. Regarding the EIM, in a counterfactual world absent the EIM, the opportunity costs associated with selling into the hour-ahead bilateral markets are still present. The EIM simply adds an additional market in which to sell excess supply and consequently, reduces both day-ahead and hour-ahead sales as compared to a counterfactual world absent the EIM.

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[38] *California ISO Welcomes BPA and Tucson Power to WEIM*, News Release, CALIFORNIA ISO (May 3, 2022) *available at* California-ISO-Welcomes-BPA-and-Tucson-Electric-Power-to-the-WEIM.pdf (westerneim.com).

Q. Do regulation reserve requirements capture the entire impact of variable renewable resources on day-ahead market sales?

A. No. Regulation reserve requirements as currently calculated by PacifiCorp only reflect uncertainty for the upcoming hour, i.e., hour-ahead forecast error. The regulation reserve requirement calculations do not yet account for day-ahead forecast error and the associated uncertainty. On a day-ahead basis, there is additional uncertainty in the forecasted levels of variable renewable resources that is not captured by the regulation reserve requirement. As opportunities to transact on an hour-ahead basis decline, there are fewer opportunities to compensate for changes in forecasted variable renewable resource output using external resources, so utilities must maintain an additional supply of dispatchable resources (excess supply) in the day-ahead timeframe, above and beyond the hour-ahead regulation reserve requirements, in order to be assured of maintaining their load and resource balance and to meet EIM requirements. This additional day-ahead uncertainty further reduces the ability and willingness of PacifiCorp and other utilities to make day-ahead sales, impacting volumes (excess supply) available in that timeframe.

Q. Will the proposed Enhanced Day-Ahead Market (EDAM) reduce the barriers to transactions between utilities on a day-ahead and hour-ahead basis?

A. Not in the 2023 forecast period relevant to this proceeding. In addition, while the EDAM could significantly enhance market liquidity relative to current operations, absent the application of constraints like market caps and the DA/RT adjustment, the Aurora model would reflect greater market liquidity than the EDAM could achieve.

Q. What are the implications to market caps given that market sales have been diminishing year over year and are expected to continue diminishing into 2023?

A. Given the historical trend of diminishing market sales and given the market fundamentals that support the trend continuing into 2023 (variable renewable resource integration and EIM expansion) it is expected that market sales will be lower in 2023 than they have been from 2018 to 2021. Setting aside the fact that this diminishing market sales trend implies that a **minimum** of averages methodology would be the most appropriate, there is certainly an overabundance of justification for use of an average of averages methodology. The third quartile of averages methodology is fundamentally flawed as it presupposes that the trend in market sales will reverse course and increase over time. This is not supported by the data.

Q. How do the 2023 market caps methodologies visually compare to the historical data?

A. Please refer to Confidential Figure 8, which shows that the market caps under either the average of averages or the third quartile of averages approach far exceed historical off-system sales volumes and are contrary to the market's clear trend.

Confidential Figure 8

[redacted]

Q. What interplay exists between market sales in Aurora and market sales in the EIM?

A. Because Aurora is an hourly model and does not contemplate the EIM, if market caps are not adjusted downwards for an expectation of increased sales in the EIM then, on a fundamental level, Aurora will sell the same excess supply twice and double count benefits. The excess supply will first be sold during system balancing within the model and then the excess supply will again be sold within the outboard EIM benefits forecast model. Not only will the excess supply be sold twice and double counted, but on a more basic level, the transmission that accommodates the market sales in

Aurora will no longer be available for donation to the EIM for that hour, and again, EIM export benefits will not be possible.

Q. Why is this interplay between the EIM benefits forecast model and the Aurora model relevant to NPC forecasts in the 2023 TAM?

A. On a net basis, generation can only be sold once. Additionally, transmission used in Aurora for market sales is transmission unavailable for use in the forecast of EIM benefits. If the market caps are not adjusted downwards to conform with the existing diminishing market sales' trends, then either the EIM benefits forecast must be reduced or the NPC forecast will, by definition, consist of a known and unresolved inaccuracy.

Q. Staff also claims that a Company discovery response indicates that the average of averages method does not consistently provide a lower forecast of off-system sales.[39] How do you respond?

A. For context, in response to a Staff discovery request, the Company provided Aurora forecasts that were used in recent Washington and California NPC filings. In analyzing the data, Staff observed that the Washington filing showed lowered sales revenue even when the market caps were increased, all other things equal. Staff thus concluded that something other than market caps was driving the over-forecast of system sales. During a review of Staff's analysis, the Company discovered an error within its response to Staff's discovery request. More specifically, the error was in the Washington sensitivity using the third quartile of averages methodology. The Company's response was supplemented with the correct data and Confidential Figure

[39] Staff/300, Dlouhy/7.

9 updates Staff's visual with the correct values, which now show that increased market caps leads to increased sales revenue.

In both concept and practice, increasing market caps in a production cost model will always increase sales revenue, all other things equal. After correcting for the error in the Company's response, the data show that increasing the market caps increases sales volume and the attendant sales revenue. This demonstrates that the average of averages method **does** consistently provide a lower forecast of off-system sales, contrary to Staff's observations.

Confidential Figure 9

[redacted]

Q. Staff claims that the entire construct of the market caps is flawed and recommends a new approach to forecasting off-system sales.[40] What is Staff's forward-looking recommendation?

A. Staff recommends that beyond the 2023 TAM, the Company either work with Energy Exemplar to modify Aurora to more accurately reflect off-system sales without needing market caps or create an econometric model to forecast future off-system sales.[41]

Q. Are either of these proposals superior to the simple and straightforward use of the average of averages to set market caps?

A. No. As an initial matter, the Company appreciates Staff's recognition that there is a potential for improvement in how Aurora models market caps for purposes of off-system sales. The Company will continue to explore both proposals made by Staff, but on initial review, neither proposal is superior to the Company's recommendation here.

Q. What are the drawbacks of working with Energy Exemplar to modify the Aurora model?

A. The Company will continue working with Energy Exemplar and is confident that with enough time and resources they could find a way to modify Aurora to more accurately model market depth. But given the significant cost to develop the software and the fact that any additional modeling software is likely to produce only marginally better results than market caps, Staff's proposal is unreasonable when

[40] Staff/300, Dlouhy/19-20.
[41] Staff/300, Dlouhy/20-21.

compared to the continued use of market caps calculated using the average of averages methodology.

Q. What are the drawbacks of developing an in-house econometric model to forecast off-system sales?

A. Developing an in-house econometric model like Staff suggests would also be extremely time and resource intensive and would likely be extremely controversial. Given the controversy around the simple proposal to reduce market caps, the Company believes that developing an entirely new and complex econometric model for off-system sales would be far more contentious.

In addition, constructing the model would be nearly a full-time job, especially after considering that the model would require near constant updating. Because the model would likely produce only marginally more accurate forecasts, the costs (in terms of time, resources, and controversy) far outweigh any potential benefits.

C. Economic Cycling

Q. Please provide an overview of Staff's economic cycling recommendation.

A. Staff does not claim that the Company's NPC is overstated because of the lack of economic cycling or propose any changes to the NPC forecast based on economic cycling. Instead, Staff simply criticizes the Company's most recent economic cycling study and recommends an arbitrary $50,000 disallowance.[42]

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

A. In the 2018 TAM, Staff proposed an adjustment intended to model the economic cycling of coal plants, which had occurred in limited historical circumstances based

[42] Staff/600, Storm/44.

on unusual market conditions in 2016 and 2017. The Commission rejected Staff's adjustment. In doing so, the Commission noted that it reviews "GRID dispatch issues to determine whether the Company is meeting its obligation to operate prudently, with prudent unit commitment and dispatch decisions that minimize costs."[43] The Commission then found that "PacifiCorp has explained that its current GRID modeling reflects historic, normalized practices regarding economic shutdowns of coal units."[44] Noting that PacifiCorp's operations may be responding to evolving market conditions, the Commission expressed an interest in understanding how PacifiCorp's operations may be changing.[45] To that end, the Commission directed PacifiCorp to hold a workshop to address economic cycling of coal plants and to make a presentation at a public meeting before the 2019 TAM on the workshop and specifically summarize any proposals identified to increase the accuracy of coal dispatch modeling due to economic outages, among other coal issues.

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

A. Yes.

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

A. Yes. In response to the Commission's interest and after workshops with Staff and other parties, PacifiCorp proposed modeling economic shutdowns for coal plants that are majority-owned by the Company, not participating in the EIM, and not under

[43] *In re PacifiCorp, dba Pac. Power 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 11 (Nov. 1, 2017).
[44] Order No. 17-444 at 11.
[45] Order No. 17-444 at 11.

operational constraints that would preclude an economic shutdown in 2019. Staff agreed with this modeling approach and the Commission approved a stipulation that included PacifiCorp's proposal for modeling economic cycling of coal plants. In the 2019 TAM, Staff specifically testified that the "number of hours of economic cycling in PacifiCorp's forecast is consistent with PacifiCorp's historic cycling hours," which Staff testified "lends credibility to PacifiCorp's forecast, but raises additional concerns that PacifiCorp's actual cycling decisions may be less than optimal."[46] Staff continued: "PacifiCorp's actual cycling decisions are a PCAM issue, not a TAM issue, and parties should address PacifiCorp's actual operation cycling decisions in the next PCAM."[47]

Q. Did the Company model economic cycling of coal plants in the 2020 TAM?

A. Yes. The Company made no changes to the modeling that was agreed to and approved in the 2019 TAM settlement. In the 2020 TAM, Staff disputed the Company's modeling, but acknowledged that the Company's method for modeling economic cycling produces more economic cycling hours than are realized in actual operations.[48] Staff ultimately entered into a stipulation that did not change the economic cycling modeling. The Commission approved the settlement.

Q. Did the Company model economic cycling of coal plants in the 2021 TAM?

A. Yes, the Company's approach in the 2021 TAM was consistent with the modeling in the 2019 and 2020 TAM. In addition, in the Stipulation that resolved the 2021 TAM PacifiCorp agreed to additional changes to enable increased modeling of coal plant

[46] Docket No. UE 339, Staff/200, Kaufman/8.
[47] Docket No. UE 339, Staff/200, Kaufman/8.
[48] Docket No, UE 356, Staff/300 Enright 17.

cycling. PacifiCorp historically included a "must run" setting for coal units in GRID to model coal units as base load operations. The "must run" setting allows coal units to reduce output to their minimum levels (which have decreased considerably in recent years) but did not allow the units to shutdown entirely, which is consistent with actual operations. In the 2021 TAM, Staff and Sierra Club recommended the removal of the "must run" setting. In the Stipulation that resolved the 2021 TAM, the Company agreed to remove the "must run" setting. PacifiCorp also agreed to perform an Economic Cycling Study that would be filed as part of the 2022 TAM (hereinafter, the 2022 Economic Cycling Study).

Q. What were the results of the 2022 Economic Cycling Study and the 2022 TAM without must run settings?

A. PacifiCorp's 2022 Economic Cycling Study and the 2022 TAM without must run settings confirmed that economic cycling generally produces minimal customer savings.

The 2022 Economic Cycling Study—which had no restraints of any kind on a unit's ability to cycle and did not consider reliability—resulted in a modest [redacted] reduction in coal generation. More importantly, however, the study showed that when coal units are allowed to cycle without restraint, economic cycling provided [redacted].

The 2022 TAM GRID study—which removed the must run settings but included several additional modeling constraints to produce results that were rational and consistent with prudent utility practice and feasible operations—showed that economic cycling reduced coal generation by only [redacted] and had a *de minimis* impact on NPC relative to a GRID study with must run settings enabled.

Importantly, both the 2022 Economic Cycling Study and 2022 TAM GRID study overstated the amount of economic cycling relative to actual operations because of GRID's perfect foresight and because neither study fully accounted for reliability issues. Imposing additional reliability constraints on economic cycling would have decreased cycling in the studies. Thus, while each study was imperfect, the imperfections tended to overstate economic cycling.

Q. How did the Commission address economic cycling in the 2022 TAM?

A. The Commission directed the Company to "complete a follow-up economic cycling study" that "should address whether economic cycling of units, with reliability considerations factored in, creates *savings for customers*."[49]

Q. Did the Company provide a follow up economic cycling study in this case?

A. Yes. The 2023 Economic Cycling Study was discussed in Company witness Wilding's direct testimony.[50] At a high level, the 2023 Economic Cycling Study results were largely consistent with prior studies and TAM filings and demonstrated that there are no "savings for customers" resulting from economic cycling.

Q. Have PacifiCorp's actual operations changed since economic cycling was first raised in the 2018 TAM?

A. No. The Company economically cycled a limited number of coal plants in 2016 and 2017 due to historical anomalies in natural gas pricing and hydro generation. Since

[49] *In re PacifiCorp, dba Pac. Power 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 9 (Nov. 1, 2021) (emphasis added).
[50] PAC/100, Wilding/42-53.

that time, the Company has not economically cycled coal plants at any significant level because of higher natural gas prices, lower hydro generation, and lower minimum operating levels at coal-fired facilities. In addition to those considerations, the continued addition of renewable resources into the Company's generation fleet requires the presence of significant online dispatchable resource capacity to integrate and reliably serve load with those new resources.

Q. Has the Company's modeling of economic cycling consistently overstated the amount of cycling relative to actual operations?

A. Yes. Production cost models (both GRID and Aurora) have perfect foresight and the ability to perfectly optimize PacifiCorp's system. As a result, Aurora (and GRID before it) model far more economic cycling than can occur in actual operations. For example, by removing the must run settings in the 2021 TAM (which maintained certain limitations), GRID forecasted [redacted] hours of offline time and approximately [redacted] End Confidential] avoided MWh for 2021. But in actual operations, PacifiCorp only achieved [redacted] hours of offline time and approximately [redacted] avoided MWh. By removing the must run settings in the 2022 TAM, GRID forecasted [redacted] cycled hours from January 2022 to May 2022. In actuality, from January to May 2022, when coal plants have been historically allowed to conduct economic cycling, the Company had only [redacted] cycled hours or [redacted] percent of the GRID forecast. In this 2023 TAM Reply Update, Aurora has forecasted [redacted] hours of offline time with the must run settings removed. Based on historical comparisons to actual operations, this forecast will likely be inaccurate as well.

Q. Did Staff provide any analysis disputing the results of the Company's 2023 Economic Cycling Study?

A. No. But Staff recommends a $50,000 disallowance because it claims that "PacifiCorp provides no evidence of the Company's attempt to locate available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, as Staff suggested, the analysis is incomplete and does not allow the Commission to determine whether economic cycling reduces costs for customers."[51]

Q. Is Staff's proposed disallowance reasonable?

A. No. First, Staff's recommendation in the 2022 TAM was that the follow-up study "look [] for available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, **or** by utilizing a new model that is able to consider reliability in its economic cycling decisions."[52] The 2023 Economic Cycling Study using Aurora was better able to consider reliability in its decision-making (although no production cost model can comprehensively account for transmission system reliability issues, such as voltage support, frequency response, and system inertia, that can arise when coal units are taken offline). In this way, the 2023 Economic Cycling Study complied with the Commission's direction and there is no basis for a disallowance.

Q. Contrary to Staff's claim, did the 2023 Economic Cycling Study examine potential shoulder season alternatives?

A. Yes. The 2023 Economic Cycling Study did examine alternatives to coal generation

[51] Staff/600, Storm/44.
[52] Order No. 21-379 at 8-9 (emphasis added).

like short term capacity contracts, which are essentially firm market transactions that the Company could use to meet load if lower cost than coal generation. The potential use of market transactions is inherent in Aurora and was therefore fully considered in the 2023 Economic Cycling Study. Importantly, if the Company were to pursue market transactions to replace coal generation, as Staff recommends, the price of the market transactions would be at least equivalent to the prices in the Company's OFPC, which reflect actual prices that the Company is subject to while transacting in the forward markets in 2023. Therefore, Staff's recommendation was tested in the Aurora runs used in the 2023 Economic Cycling Study because Aurora was able to select market transactions to replace coal generation if it was economic to do so. The conclusions in the 2023 Economic Cycling Study are therefore sound and demonstrate that there are no customer savings associated with economic cycling.

If Staff was requesting that the Company identify specific potential counterparties and/or issue actual market solicitations for specific capacity contracts to use in the modeling, then that request was unclear and would be entirely unreasonable for purposes of an economic cycling study that Staff agrees is purely informative.

Q. Did Staff express any other concerns with the 2023 Economic Cycling Study?

A. Yes. Staff claims that PacifiCorp could have set the must run "control off for the least efficient unit in the multi-unit plants, one-by-one in the shoulder seasons and starting with the least efficient unit of these plants, or perhaps only working with the least efficient unit in the multi-unit plants it wholly owns, might produce insights that positively influence actual operations."[53]

Q. Would reducing the number of units that are capable of economic cycling as Staff recommends produce insights that positively influence actual operations?

A. No. The Company's actual operations currently gain insight from a production cost model developed by Power Costs Inc., which is specifically geared for generation portfolio optimization across the time horizons of actual operations. As mentioned earlier in my testimony, the modeling of NPC in the Oregon TAM has persistently under-recovered NPC in Oregon rates and as such is not yet at the level of accuracy that would enable useful insights for positive influence of actual operations.

Q. Staff also claims the fact the Company does not economically cycle coal units in actual operations should not matter for purposes of an economic cycling study because the "purpose of economic cycling modeling is to ascertain the circumstances, if any, under which reduction in coal unit dispatch can result in reduced power costs without producing any reliability issues."[54] How do you respond to this claim?

A. Staff implies that modeling economic cycling may cause the Company to modify actual operations in a way that conforms to the modeling. But Staff's implication assumes that the economic modeling produces results that the Company should replicate in actual operations (assuming it is possible to do so, given the reliability issues noted above). The 2023 Economic Cycling Study, just like the 2022 Economic Cycling Study, and the several TAM filings without the must run setting confirm that

[53] Staff/600, Storm/44.
[54] Staff/600, Storm/41.

there are little to no economic savings resulting from cycling coal units and, in fact, NPC likely increases while reliability decreases.

Q. Do you have any concerns about continuing to remove the must run setting from Aurora?

A. Yes. For several years the Company has turned off the must run setting in GRID and now in Aurora. The results this year show that NPC increases without the must run setting. In addition, without the must run setting, Aurora is required to solve a far more complex model and takes approximately 10 hours to complete a single one-year run and approximately 40 hours to complete a single ten-year run. Given the short timelines inherent in the TAM schedule (e.g., the updates required in November), the Company is concerned that it may not have sufficient time given how long it takes Aurora to solve without the must run setting. Given that removing the must run setting increases NPC and decreases modeling efficiency, it makes little sense to continue to remove the must run setting.

Q. Has PacifiCorp performed a sensitivity on the impact of turning the must run setting back on in Aurora?

A. Yes, it resulted in a [redacted] reduction to total-company NPC. While the magnitude is more significant since the Initial Filing, the removal of the must-run setting continues to result in higher NPC.

D. Minimum Take Modeling

Q. How did PacifiCorp previously model minimum take obligations in its CSAs when using GRID?

A. Prior to the transition to Aurora, GRID could accept only one coal price so when a

CSA had tiered pricing (e.g., to reflect a take or pay obligation, which is discussed in more detail below) the Company was required to model a dispatch price in GRID based on the unit's incremental cost, excluding the sunk costs associated with the minimum take obligation. The dispatch price was used to determine the unit dispatch in GRID and the costing tier (which included fixed costs and represents the unit's average cost) was used to calculate NPC charged to customers.

Q. Was PacifiCorp's minimum take modeling disputed in the 2022 TAM?

A. Yes. Sierra Club argued that the Company's incremental pricing used to determine unit dispatch improperly excluded fixed costs and was therefore too low.[55]

Q. In the 2022 TAM, did the Commission disagree with the Company's modeling of minimum take levels in its CSAs?

A. No. The Commission did not require PacifiCorp to "change its specific modeling inputs" because the Commission did "not find that PacifiCorp acted unreasonably by accounting for minimum take levels in its modeling of resource operation."[56]

Q. Has the transition to Aurora largely resolved the dispute regarding minimum take modeling using GRID?

A. Yes. The prior dispute resulted from the fact that GRID could accept only one coal price. Aurora can accept multiple tiered pricing consistent with the terms of a specific CSA.

Q. Did the Commission direct PacifiCorp to include additional information in this TAM related to its minimum take modeling?

A. Yes. The Commission directed PacifiCorp to include four years of data that shows

[55] *See* Order No. 21-379 at 10-11.
[56] Order No. 21-379 at 12.

the "costing tier for each plant for each year, and the differential between the initial incremental price and the costing tier price so parties can consider the variations in the incremental price discount from plant to plant."[57]

Q. What information did PacifiCorp provide in response to this directive?

A. For 2020, 2021, and 2022, PacifiCorp provided the values for the costing tier and incremental tier for each coal unit, as reflected in the GRID runs used in each year's respective TAM. For 2023, PacifiCorp reported the tiered CSA prices because Aurora does not require the incremental and costing tier framework that applied to GRID.

Q. Did Staff criticize the information provided by PacifiCorp?

A. Yes. Staff recommends an arbitrary $50,000 disallowance because it claims that the information provided is incomplete.[58]

Q. What information does Staff claim is missing?

A. Staff argues that the Company provided the costing tier and incremental tier but did not provide the difference between those two figures, i.e., PacifiCorp did not subtract the incremental tier from the costing tier. While the Company believes this simple arithmetic is easily achieved given that the Company provided the values in an Excel spreadsheet, to be fully responsive to Staff's concern, the Company has reproduced the data in Confidential Exhibit PAC/604, including the difference between the two prices.

[57] Order No. 21-379 at 12.
[58] Staff/600, Storm/49.

Q. Is the historical differential between the costing and incremental tier used in GRID relevant going forward?

A. No. As discussed above, the transition to Aurora has resolved the prior modeling disputes and the Company no longer relies on a single dispatch tier price. As Staff acknowledged, "Because Aurora is capable [of] modeling coal fuel price tiers directly, no iterative or outboard adjustments were required."[59] Staff also verified that the Company's fuel price inputs were accurate.[60]

E. EIM Benefits

Q. Please provide an overview of Staff's recommendations related to the forecast of EIM benefits.

A. Staff provided two recommendations: (1) a modification to the forecasted GHG benefits and (2) a modification to the forecasted energy transfer benefits.

Q. Turning first to the GHG benefits, what is Staff's specific recommendation?

A. Staff recommends that the Company's GHG benefit forecast include the [redacted][61]

Q. What is your response to Staff's recommendation?

A. The Company agrees with Staff's recommendation. The Company's calculation shows a decrease to total-company NPC of [redacted] (total-company).

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[59] Staff/800, Anderson/5.
[60] Staff/800, Anderson/5.
[61] Staff/100, Enright/29.

Q. What is Staff's recommendation related to the EIM transfer benefits?

A. Staff recommends an increase to the EIM transfer benefits resulting from the correction to a model input used to derive the benefit forecast.

Staff also recommends that the Company modify its EIM transfer benefits by modifying one of the regressions used to generate the benefit forecast.[62] Adopting this recommendation decreases EIM benefits.

Q. How do you respond to Staff's EIM energy transfer benefit recommendations?

A. The Company has corrected the error in the EIM transfer benefit model input and realizes an updated EIM transfer benefit forecast of [redacted][63] (total-company) consistent with Staff's findings. The Company accepts Staff's recommendation regarding the modification of one of the regressions used to generate the forecast. After correcting for an error in Staff's workpaper, wherein the PACE market prices were used in the PACW export benefit calculation, this modification results in the EIM transfer benefit forecast updating to [redacted] (total-company). After updating the model inputs with the latest available data, the EIM transfer benefit forecast updates to [redacted] (total-company). The error correction, the regression modification and the updates all together result in an increase to EIM GHG and transfer benefits and corresponding decrease to total-company NPC of [redacted] (total-company) relative to the Initial Filing.

Q. Do you have any concerns with imputing EIM transfer benefits outside of the Aurora model?

A. Yes. As discussed above, because the EIM transfer benefits derive from market sales

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[62] Staff/300, Dlouhy/29.
[63] Staff/300, Dlouhy/29

that are duplicative of off-system market sales included in the Aurora model, there is a double count of the benefits from these sales. This double counting is further support for reducing the market caps so that it is less likely that Aurora models the same off-system sale (and resulting revenue credit) that is later imputed through the out-of-model EIM transfer benefit calculation.

F. QF Forecast

Q. How does the Company forecast QF costs in the TAM?

A. The forecast for QF costs in the TAM is based on QF contracts with specific prices and terms. The contract may specify an exact quantity of capacity and energy, or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. Prices may also be specifically stated, may refer to a rate schedule or a market index, or may be based on some type of formula. Every QF contract is modeled individually. For QF contracts with a nameplate capacity greater than 10 MW, the delivery energy forecast is based on 48-month normalization assumptions. For QF contracts with a nameplate less than or equal to 10 MW, the delivery energy forecast uses the actual delivery schedule available before the filing. For renewable QFs with a nameplate greater than 10 MW, the forecasted capacity factor is based on either the full history if the QF has been online longer than four years or based on a blend of history and 50^{th} percentile generation forecasts developed by the Company's third-party engineering firm hired for modeling and siting analysis of generation resources.

In addition, consistent with methodology change adopted in the 2018 TAM, PacifiCorp's QF forecast also includes an adjustment for the contract delay rate

(CDR). The CDR is calculated based on the average days between the QF's expected commercial operation date (COD) in the final TAM and its actual COD (or more recently estimated COD) from the last three TAM cases, weighted by the size of the delayed QF. PacifiCorp applies the CDR to all the new QFs coming online in the rate year.

Q. Staff contends that the Company continues to over-forecast QF generation and recommends an adjustment that reduces forecast QF generation, which decreases NPC.[64] How did Staff calculate its proposed adjustment?

A. Staff compared actual QF costs to forecasted QF costs from 2016 through 2021 and concluded that PacifiCorp has continued to over-forecast QF generation and costs. Based on this assessment, Staff recommends a decrease of [redacted] in forecast QF costs for 2023, which equates to a reduction in Oregon-allocated NPC of [redacted].[65]

Q. Is Staff's recommendation in this case conceptually the same as its recommendation in the 2022 TAM?

A. Yes. In the 2022 TAM, Staff recommended a substantively identical adjustment to QF costs.

Q. Did the Commission accept Staff's adjustment in the 2022 TAM?

A. No. The Commission rejected Staff's adjustment because it "resemble[d] a true-up of one line item of NPC to align with actual past levels."[66] Because Staff's QF

[64] *See* Staff/400, Bolton/7.
[65] Staff/400, Bolton/9.
[66] Order No. 21-379 at 38.

adjustment continues to be a true-up of one line item with actual past levels, the Commission should reject it once again.

Q. While the Commission rejected Staff's QF adjustment in the 2022 TAM, did the Commission express concern over the Company's QF forecasting?

A. Yes. The Commission directed PacifiCorp to provide updated data for 2021 comparing the forecast to actual QF generation and to address why it has continued to over forecast QFs in recent years.[67]

Q. Has the Company provided updated 2021 data on QF generation?

A. Yes. Please refer to Confidential Table 5, which shows QF forecast error percentage from 2016 to 2021.

Confidential Table 5

	Difference between Forecast and Actuals (%)
	QFs (MWh)
Year	Percent
2017	[redacted]
2018	
2019	
2020	
2021	
Average	

Q. What conclusions can you draw from the updated analysis?

A. The 2021 data shows an improving accuracy rate. Additionally, the 2021 data shows that QFs with a nameplate capacity greater than 10 MW have an error rate of

[67] Order No. 21-379 at 38.

approximately [redacted] while QFs with a nameplate capacity less than or equal to 10 MW have an error rate of approximately [redacted] As stated earlier in my testimony, for QF contracts with a nameplate less than or equal to 10 MW, the delivery energy forecast uses the actual delivery schedule available before the filing. Moving forward, the Company will explore using delivery energy forecasts based on 48-month normalization assumptions for a subset of the QF contracts with a nameplate less than or equal to 10 MW in order to improve forecasting accuracy.

As an additional item of note, the aggregate QF forecast error percentage is substantially lower in magnitude than the total-company NPC forecast error percentage, substantially lower in magnitude than the sales volumes forecast error percentage, and substantially lower in magnitude than the total generation forecast error percentage as tabulated in Confidential Table 6. When examined in isolation, QFs may appear to have a high forecast error percentage. However, when examined within the context of wholesale sales, other sources of generation and within the overall context of NPC it becomes apparent that the QF forecasts are relatively accurate and in least need of improvement.

Confidential Table 6

Difference between Forecast and Actuals (%)
[redacted]

G. Planned Outage Schedule

Q. Please describe the Company's proposal to refine how it models planned outages in the TAM.

A. The Company proposes replacing normalized outage assumptions with actual budgeted and/or planned outages to more accurately reflect the planned outages that are expected during the rate year.

Q. Is the Company's proposal consistent with how NPC is forecast for other Oregon utilities?

A. Yes. It is my understanding that both Idaho Power and Portland General Electric forecast outages based on utility planning, rather than using a historical four-year average.[68] PacifiCorp's proposal therefore aligns its NPC forecasting methodology with that used by other utilities in Oregon.

[68] For example, PGE's Schedule 125 states that its annual power cost update filing includes an update for "projected planned plant outages." In docket UM 1355, the Commission approved a stipulation for Idaho Power that allowed it to "continue to forecast its planned outages." *In re Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Docket No. UM 1355, Order No. 10-414, App. C at 7 (Oct. 22, 2010).

Q. Does Staff agree with the Company's proposal?

A. No. Staff recommends that the Company continue to use a four-year average to create a normalized outage schedule even if the normalized outage schedule is unlikely to reflect the actual outages experienced in the rate year.[69]

Q. Staff argues that using a four-year average reduces year-to-year "lumpiness" and smooths the effects of planned outages.[70] Is this a reasonable basis for maintaining the current methodology?

A. No. The purpose of the TAM is to produce the most accurate NPC forecast for the following calendar year, in this case 2023. Using the actual planned outage schedule for 2023 will produce a more accurate NPC forecast even if the forecast is lumpier because some years have more planned outages than others.

Q. Staff also objects to the use of budgets because of the lack of transparency, particularly as compared to using quantifiable data based on recent historical experience.[71] How do you respond to this concern?

A. The Company's process for scheduling planned outages is not a "black box" process and details on this process are outlined later in my testimony. Additionally, Confidential Figure 10 shows that on a MWh basis from years 2019 to 2021, the budgeted outages have a [redacted] error rate as compared to the outages derived from historical averages, which have a [redacted] error rate. Furthermore, it is my understanding that both Idaho Power and Portland General Electric forecast outages

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[69] Staff/500, Fjeldheim/3.
[70] Staff/500, Fjeldheim/3.
[71] Staff/500, Fjeldheim/3.

based on utility planning, indicating that the approach is both tested and workable. The Company should be afforded the option for equitable treatment.

Confidential Figure 10

[redacted]

Q. Please explain the process for developing the planned outage forecast schedule within the context of the budget.

A. First, the generation group will develop the work scope, staffing plans, preferred start date, and required duration for each plant outage as part of the 10-year budget planning process

Second, the front office group reviews the proposed outage schedules and durations taking into consideration the forward markets' price curves, load forecasts, transmission path constraints and system control requirements. The front office group will then propose schedule revisions as necessary.

Third, the front office group then summarizes the benefits associated with the proposed schedule revisions. If there are valid and justifiable reasons why the front office group's schedule revisions cannot be accommodated, the generation group will be required to provide business case justification to substantiate deviation from the schedule revisions proposed by the front office group.

Fourth, after the final schedule is justified, the generation group will then review and seek final approval from executive management. Once approved, the planned outage schedule will become part of the budget.

H. Thermal Attributes

Q. Please describe the Company's refined modeling of thermal plant attributes.

A. To account for the fact that thermal plants generate less when temperatures are higher, the Company refined its modeling of this operational constraint by decreasing the maximum generation capacity at certain plants during the summer months.

Q. What is Staff's recommendation regarding this modeling refinement?

A. Staff recommends that the Commission reject the Company's refined modeling because the Company did not provide any "engineering studies, historical thermal plant performance data, or any other quantifiable state to support" the refinement.[72]

Q. How do you respond?

A. Attached to this testimony as Confidential Exhibit PAC/605 are engineering documentation on the effects of ambient temperature on the generation output of gas turbines and steam turbines as found within Company gas plants and coal plants. These studies demonstrate the reasonableness of the Company's reduction to thermal generation during summer months.

[72] Staff/500, Fjeldheim/6.

Q. Is the reduced generation included in the TAM modeling consistent with generally industry standards?

A. Yes. The *ASME Performance Test Code 46-2015, Overall Plant Performance*[73] has industry standard correction factors for ambient temperatures, among other things. This code outlines the basic industry-wide knowledge regarding the relationship between high temperatures and lower generation output that exists at many of the Company's thermal plants.

I. Model Validation

Q. As part of the transition to Aurora, did the Company perform any analysis to verify the accuracy of Aurora?

A. Yes. As described in the direct testimony of Company witness Wilding, the Company included a robust validation process that included test reports comparing Aurora and GRID, among other analyses.[74]

Q. Has Staff requested additional model validation?

A. Yes. Staff recommends that PacifiCorp:

> provide backcast model validation runs similar to the backcast provided in Docket No. UE 339. The backcasts should use actual 2022 and 2023 data, respectively, while keeping all other inputs and assumptions the same as those in the relevant TAM. PacifiCorp should provide the first validation run in connection with its 2024 TAM and the second in connection with its 2025 TAM.[75]

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[73] *PTC-46, Overall Plant Performance*, THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS (2015) *available through* https://www.asme.org/codes-standards/find-codes-standards/ptc-46-overall-plant-performance.
[74] PAC/100, Wilding/17-18.
[75] Staff/800, Anderson/3.

Q. Do you believe a backcast is necessary to validate Aurora's ability to accurately forecast NPC?

A. No. When PacifiCorp performed a backcast in docket UE 339, it was intended to verify the accuracy of GRID, which was a proprietary production cost model developed by PacifiCorp and used exclusively by PacifiCorp. Aurora, on the other hand, is a third-party model that is widely used by other utilities throughout the region, including in Oregon. It is unclear why Staff disputes Aurora's ability to accurately forecast NPC given its widespread use, but the burden of performing a backcast analysis is unwarranted given the differences between Aurora and GRID. Performing a backcast is the equivalent of doing another TAM filing and requires a similar amount of preparation in order to complete.

V. REPLY TO CUB

A. Aurora Model

Q. Please describe CUB's concern over the process used to validate Aurora.

A. CUB acknowledges that the Company compared the output of a GRID and Aurora model run and the results were within 0.8 percent.[76] But CUB's testimony leaves the impression that the model runs were from different years, i.e., that the Aurora run forecast NPC for 2023 and the GRID run forecast NPC for 2022 (or some other year) and therefore concludes that the differences between the Aurora and GRID runs could be due to "changes in market conditions during the forecast period[.]"[77]

[76] CUB/100, Jenks/4.
[77] CUB/100, Jenks/5.

Q. Did the Company's model validation GRID and Aurora runs forecast NPC for different years?

A. No. To be clear, PAC/103 and PAC/104 are the GRID and Aurora runs used for the model validation process. Both runs forecast NPC for calendar year 2021. So the differences between the model results are not a result of different forecast periods.

Q. CUB also points out that even though the model validation shows end results that were within 0.8 percent, individual elements differed by far more.[78] Is this unexpected?

A. No. As explained in my direct testimony, there are differences between the optimization logic used by Aurora and GRID and each model uses inputs with different levels of granularity. Together, these differences will result in different dispatch of resources, and different balancing transaction forecasts. This is why the validation process compared the overall outcome of the NPC test report.

Q. CUB questions how much of the increase in NPC forecast in this case is attributable to the transition to Aurora, rather than expected market conditions.[79] How do you respond to this concern?

A. To the extent that the higher NPC forecast is attributable to the Aurora model, such an outcome is not unreasonable. CUB testifies that "GRID was not known for its accuracy" and no party has disputed that the Company has under-recovered its NPC by consistent and significant amounts in recent years. To the extent that the historical under-recovery resulted from GRID under-forecasting NPC (which is a logical

[78] CUB/100, Jenks/4-5.
[79] CUB/100, Jenks/6.

conclusion based on CUB's testimony), creating a more accurate forecast using Aurora is superior even if the more accurate forecast increases NPC.

B. Market Capacity Limits

Q. CUB acknowledges that no model is perfect but testifies that "PacifiCorp only has an incentive to look for modeling improvement that increase the costs charged to customers."[80] How do you respond?

A. The Company's incentive is to create an accurate NPC forecast that provides a reasonable opportunity for the Company to recover its prudently incurred costs. It is undisputed that the Company has consistently under-recovered those prudently incurred costs because the NPC forecast has been consistently set too low. Given that the forecast has been consistently too low, it is not surprising that modeling refinements are largely targeted at capturing costs that the forecast previously did not include. Refining a model to decrease forecasted NPC when the model has consistently under-forecast NPC is logically not going to produce a more accurate forecast.

Q. CUB argues that reduced market caps are no longer necessary because Aurora already reduces system balancing sales relative to GRID.[81] How do you respond?

A. Market caps replicate the limited market depth or lack of liquidity experienced in the real world at various trading hubs where the Company transacts. Changing models, from Aurora to GRID, does not affect these real-world limitations. And as discussed above, Aurora (like GRID) does not have an internal mechanism to model market

[80] CUB/100, Jenks/6.
[81] CUB/100, Jenks/8.

depth or liquidity without market caps. The single year of historical data where Aurora produced fewer market transactions does not demonstrate that reduced market caps are no longer necessary, particularly in light of the analysis set forth above.

Q. CUB also claims that the Company overstates the problem because it focuses on the total dollar amount of the over-forecast sales and does not account for offsetting costs, like the increased fuel costs that produce the excess energy that is sold.[82] How do you respond to this argument?

A. The Company disagrees. Aurora accounts for all the offsetting costs discussed by CUB and when the market caps are refined using the average of averages methodology, overall NPC increases by nearly $6 million on an Oregon-allocated basis, which is significant. Put another way, using excessive market caps produces $6 million in forecasted *net* revenues that cannot be realized in actual operations. So taking into account all of the offsetting costs CUB references still results in significant revenues that decrease NPC, in this case by $6 million.

Q. CUB also argues that the Company's market sales have been increasing as a result of greater renewable generation in the Company's generation mix.[83] Is this true?

A. No. As discussed above and shown in Confidential Figure 6, the impact of increased renewable generation has had the opposite impact on the volume of market sales. Importantly, market caps are a volumetric (megawatt) limitation imposed on market sales within Aurora at various trading hubs. CUB's argument is based on a

[82] CUB/100, Jenks/8.
[83] CUB/100, Jenks/9.

comparison of nominal wholesale sales revenue, unadjusted for changes in market prices, and the associated official forward price curves.

Moreover, as discussed earlier in my testimony, the logic behind CUB's argument falters because greater renewable generation on the system has required PacifiCorp (and other market participants with similar portfolios) to hold back dispatchable resources, as regulation reserves, to enable reliable and efficient integration of intermittent generation. The Company has made investments in renewable resources to cost-effectively serve customers, not to operate them as merchant generators. The increase in renewable generation therefore has not increased market sales.

Q. CUB also claims that the Company has over-forecast short-term market purchases.[84] Is this true?

A. Yes, but the amount is de minimis when compared to market sales. The Company has over-forecast short-term market sales by [redacted] using CUB's comparison of the different in cost—not volumes—between forecasted and actual short-term purchases. Confidential Table 7 tabulates and compares the Company's total-company historical dollar forecasts of short-term market purchases to the Company's historical dollar actual short-term market purchases. The data shows that over the past four years the average over-forecast (average of the last four year's "(Below)/Above Forecast" delta) is [redacted] of the last four years' average "Actual." CUB's reference to over-forecast short term market purchases is from an average of the delta across five years, from 2016 to 2020.

[84] CUB/100, Jenks/9.

Confidential Table 7

	Short-Term Purchases ($)		
	Actual	Forecast	(Below)/Above Forecast
2012	[redacted]		
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			

Q. How does the over-forecast of short-term firm market sales compare using similar analysis?

A. The over-forecast of short-term firm market sales is [redacted]. Confidential Table 8 tabulates and compares the Company's total-company historical dollar forecasts of short-term market sales to the Company's historical dollar actual short-term market sales. The data shows that over the past four years the average over-forecast (average of the last four year's "(Below)/Above Forecast" delta) is [redacted] of the last four years' average "Actual." This data shows that the over-forecast of market sales revenue is substantially greater than the over-forecast of market purchase costs, which is consistent with the Commission's findings in the last rate case.

Confidential Table 8

	Short-Term Sales ($)		
	Actual	Forecast	(Below)/Above Forecast
2012	[redacted]		
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			

Q. Is a comparison of forecasted to actual costs and revenues decisive for purposes of analyzing market caps?

A. No. The more appropriate comparison is the volumetric change observed in Confidential Table 4, which shows a volumetric over-forecast of short-term market sales of [redacted] using the same averages comparison as discussed above for Confidential Table 8. This distinction between volume and dollars is especially important because market caps are a volumetric concept through which volumetric limitations are imposed on the market sales volumes within Aurora at various trading hubs. Dollars and volumes are not fungible through direct comparison in this context.

Q. CUB also points to the relationship between off-system sales and EIM benefits as a basis to reject a lower market cap.[85] How do you respond?

A. As discussed earlier in my testimony, CUB is correct that there is a trade-off between the EIM and off-system sales because resources that are committed to the EIM cannot be used for off-system sales and vice versa. This argument, however, supports *lower*

[85] CUB/100, Jenks/9.

market caps because including both the sales revenue for Aurora sales forecasts that are then forecast outside-the-model as EIM sales *and* including the resulting EIM sales revenue constitutes a double counting of benefits because the same sale is counted in Aurora as a system balancing sale and counted outside Aurora as an EIM benefit.

Q. CUB also claims that data from 2020 and 2021 are not necessarily reflective of the future because of the impacts of COVID-19.[86] Is that a reasonable basis to reject the refined market caps?

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

C. Planned Outage Schedule

Q. Please explain CUB's concern over the Company's proposal to use actual planned outage forecasts instead of a four-year average.

A. CUB recommends rejecting this modeling change because even though CUB concedes that it "seems like it will be more accurate, CUB is concerned that, over

[86] CUB/100, Jenks/9.

time, we will capture more than the actual volume of planned maintenance outages."[87] CUB points out that planned outages are subject to change due to unforeseen and evolving conditions during the year that may delay or postpone a planned outage that was assumed when rates were set in the TAM.

Q. How do you respond to CUB's concern?

A. Data from 2019 to 2021 demonstrate that, on average, actual planned outage forecasts capture *less* than the actual volume of planned maintenance. This is illustrated in Confidential Figure 10 in my reply to Staff's testimony.

D. DA/RT Adjustment

Q. Please explain CUB's concerns over the Company's refined DA/RT adjustment.

A. CUB's first concern focuses on the transition to Aurora, which CUB argues shows a significant change to the DA/RT adjustment.[88]

Q. How do you respond to this concern?

A. The DA/RT adjustment is an out of model calculation to account for the historical price differences between the Company's purchases and sales, in actual operations, as compared to the monthly average actual market prices. The transition to Aurora does not impact the Company's purchases and sales in actual operations, nor does it impact the monthly average actual market prices.

Q. What is CUB's second concern regarding the refined DA/RT adjustment?

A. CUB argues that there is no evidence that changing the historical data from flat numbers to a percentage is more accurate.[89]

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[87] CUB/100, Jenks/11.
[88] CUB/100, Jenks/14.
[89] CUB/100, Jenks/14-15.

Q. How do you respond to this concern?

A. As discussed above, the Company's analysis demonstrates that a percentage adder is more suitable for capturing the historical interplay between monthly average market prices and Company transactions.

Q. CUB also reiterates concerns that the DA/RT adjustment relies on historical data that is non-normalized.[90] Is this a valid concern?

A. No. The Commission expressly rejected this criticism of the DA/RT adjustment the first time CUB raised it.[91]

VI. REPLY TO AWEC

A. Oregon Situs Assignment Calculation

Q. AWEC requests that the Company explain how situs assigned QFs are addressed in the TAM.[92] How do you respond?

A. The energy valued by situs assigned QFs are priced at the Reasonable Energy Price, which is defined as an hourly blending of the OFPC used to develop the relevant contract price. Then, an outside-the-model adjustment is made to situs assign any QF costs above the reasonable cost of energy to the appropriate state.

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[90] CUB/100, Jenks/15.
[91] Order No. 15-394 at 4 ("First, with regard to CUB's concern that this adjustment should be rejected because it is not normalized, we note that PacifiCorp's use of three years of data is sufficient to smooth out variations to generate a reasonable estimate of expected spot price differentials.").
[92] AWEC/100, Mullins/11.

B. Non-Firm Wheeling Error

Q. AWEC claims that PacifiCorp's workpapers contain an error in the calculation of the non-firm wheeling expense.[93] Is that true?

A. Yes. PacifiCorp has corrected this error which results in a decrease to total-company NPC of [redacted] (total-company).

C. Short-Term Transmission

Q. AWEC claims that it is unable to verify how short-term transmission is modeled in Aurora.[94] Can you describe how short-term firm transmission is modeled?

A. The Company model's short-term firm transmission using 48 months of historical short-term transmission data to derive hourly average capacity on various short-term transmission paths. These paths and capacities are then modeled in Aurora, incremental to the pre-existing topology.

Q. AWEC also questions whether the Company's approach is consistent with prior practice that used 48 months of historical data.[95] Did the Company change its modeling in this case?

A. No. The Company has not changed its modeling in this case.

Q. AWEC further claims that there was an error in how short-term transmission was modeled in Aurora.[96] Is AWEC correct?

A. No. First, regarding the short-term transmission transactions from Avista to Mid-Columbia,[97] they do not initiate within Aurora's "Idaho Power Company West" zone.

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[93] AWEC/100, Mullins/12.
[94] AWEC/100, Mullins/12.
[95] AWEC/100, Mullins/13.
[96] AWEC/100, Mullins/13.
[97] AWEC/100, Mullins/13.

These transactions are from a point at the intersection of Avista's system and the Bonneville Power Administration's system, which is more appropriately located in Washington.

Second, regarding the transactions from Red Butte to Mead, Mead is not a market hub in Northern Nevada,[98] it is a market hub by the Hoover dam on the outskirts of Las Vegas, which is in Southern Nevada. Furthermore, the Red Butte substation, at the edge of south-east Utah, is closer to Mead than it is to the Sigurd substation which is at the confluence of Aurora's Utah South zone. Within Aurora's zonal topology these two areas (Red Butte and Mead) are therefore appropriately considered "intra-bubble."

Third, regarding short term transmission transactions involving transmission acquired by the Company on PacifiCorp's transmission system, there are multiple historical transactions which detail such acquisitions.

D. Market Capacity Limits

Q. AWEC recommends that the market caps be eliminated given the move to Aurora, which would reduce Oregon-allocated NPC by $19 million.[99] What is the basis for AWEC's recommendation?

A. AWEC claims that Aurora produces a "level of sales that is significantly below historical levels, so continuing to apply a limit on market sales is no longer necessary."[100] The discussion below responds to AWEC's rationale for eliminating market caps in Aurora.

[98] AWEC/100, Mullins/13.
[99] AWEC/100, Mullins/15.
[100] AWEC/100, Mullins/15.

Q. How does AWEC support its claim that "continuing to apply a limit on market sales is no longer necessary?"[101]

A. AWEC produced a figure showing sales volumes from 2016 through 2021 (excluding bookouts)[102] and, based on that figure, AWEC argues that because the Aurora-modeled results without market caps are less than the historical average from 2016 through 2021, market caps are no longer necessary.

Q. Is AWEC's reasoning sound?

A. No. First, AWEC's analysis incorrectly uses six years of historical data to derive the average that AWEC then compares to the current forecast. Market caps, however, are based on four years of historical data. Given the declining transaction volumes in recent years (discussed above) relying on six years of data is unreasonable.

Second, AWEC removes the impact of the DA/RT adjustment even though the fundamental premise of that adjustment is entirely unrelated to market caps.

Third, the purpose of market caps is to replicate the limited market depth or lack of liquidity experienced in the real-world at various trading hubs across which the Company transacts. Until this real-world issue is no longer present, it is fallacious to argue that market caps are no longer necessary.

Given the above deficiencies, the results of the analysis are unpersuasive.

Q. AWEC claims that higher market prices should lead to higher sales volumes.[103] Do you agree?

A. In a world where all other things are equal, higher market prices will result in higher

[101] AWEC/100, Mullins/15.
[102] AWEC/100, Mullins/16, Figure 1.
[103] AWEC/100, Mullins/16.

sales volumes ***if*** there is excess supply, available transmission, market depth and market liquidity. Unfortunately, in actual operations, all other things are never equal, and the market is frequently constrained by one of the aforementioned factors.

Q. AWEC also claims that the volumes associated with the DA/RT adjustment contribute more volume to the sales forecast than Aurora and therefore eliminating the DA/RT volumes would serve the same purposes as imposing lower market caps to limit off-system sales volumes.[104] How do you respond to this claim?

A. If the purpose of the DA/RT adjustment were to influence sales volumes then AWEC's argument might hold up under scrutiny. However, the DA/RT adjustment is intended to correct for an issue that is unrelated to the issue being addressed by market caps. The DA/RT adjustment's purpose is to account for the real-world historical price differences between the Company's purchases and sales as compared to the monthly average market prices. The purpose of market caps is to replicate the limited market depth or lack of liquidity experienced in the real world at various trading hubs across which the Company transacts. Until these separate real-world issues are no longer present, it is fallacious to argue that the DA/RT adjustment can be removed simply because a portion of its effect may coincide with a portion of the market caps' effect.

Q. Has AWEC made a similar proposal in the past?

A. Yes. When PacifiCorp first introduced the DA/RT adjustment in the 2016 TAM,

[104] AWEC/100, Mullins/17.

Mr. Mullins, on behalf of ICNU, recommended that the Commission eliminate market caps if it approved the DA/RT adjustment.[105] The Commission rejected AWEC's adjustment in that case.

E. Emergency Purchases

Q. AWEC recommends an adjustment that reduces the cost of emergency purchases modeled in Aurora, which reduces Oregon-allocated NPC by $2.4 million.[106] As context, what is an emergency purchase?

A. As explained in greater detail in the direct testimony of Company witness Wilding,[107] emergency purchases are modeling constructs in Aurora that occur either when the model has no other method to satisfy the load obligation because of the modeling constraints, or in rare cases when the emergency purchase price is less than the cost of an alternative solution.

Q. How are emergency purchases priced?

A. Emergency purchases are priced at 125 percent of market. AWEC incorrectly states that emergency purchases are 150 percent of the nearest market price.

Q. Are emergency purchases real?

A. No. They do not reflect actual transactions that the Company could make in actual operations. Rather, they are purely a modeling construct.

[105] Order No. 15-394 at 3.
[106] AWEC/100, Mullins/22.
[107] PAC/100, Wilding/41.

Q. AWEC claims that emergency purchases comprise approximately 8 percent of the total purchases modeled in Aurora.[108] Is this a meaningful percentage?

A. No. Emergency purchases are a modeling construct that represents energy put onto the system and as such should be compared with all other sources that also put energy onto the system. This includes all purchased power and all owned generation. Recalculating emergency purchases as a percentage of purchased power and owned generation shows that emergency purchases comprise approximately 0.43 percent of all energy that was put onto the system.

Q. Are emergency purchases included in the DA/RT adjustment?

A. No. The DA/RT adjustment is based on actual historical transactions PacifiCorp made in the day ahead and real time market. Because emergency purchases are not real, they are not included in the DA/RT adjustment. Contrary to AWEC's claim, emergency purchases are not "actual historical costs" and therefore have no place in the DA/RT analysis.

Q. AWEC claims that the 125 percent adder for emergency purchases does not belong in the NPC forecast because the "DA/RT adjustment already considers the high cost of making emergency purchases when the system is constrained so it is unnecessary to add additional cost into NPC for the emergency purchases generated in Aurora."[109] Is this correct?

A. No. As stated above, emergency purchases are not real and are therefore not incorporated into the DA/RT adjustment. AWEC's adjustment relies on the incorrect assumption that the Company has historically made emergency purchases at

[108] AWEC/100, Mullins/21.
[109] AWEC/100, Mullins/22.

125 percent of market in actual operations. Because this assumption is untrue, AWEC's adjustment has no merit.

VII. REPLY TO SIERRA CLUB

A. Overall Coal Costs

Q. Sierra Club points out that coal costs have increased relative to the 2022 TAM and despite the increase PacifiCorp forecasts higher coal generation compared to the 2022 TAM.[110] Is this result unexpected?

A. No. As natural gas costs and associated market prices have increased in the 2023 TAM relative to the 2022 TAM, coal costs on a dollar-per-megawatt-hour basis are lower relative to other supply options, like natural gas generation and market purchases. Therefore, when put within the context of other system costs, coal generation is more economic in this 2023 TAM than it was in the 2022 TAM. This leads to increased coal generation as part of the system's optimized dispatch, which lowers NPC. Absent the coal generation in the 2023 TAM, NPC would be significantly higher.

B. Coal Unit Dispatch Modeling

Q. As background, please define the incremental cost of production.

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

[110] Sierra Club/100, Burgess/13.

Q. Please define the average cost of production.

A. The average cost of production is the ratio of the total cost of production to the total energy produced. For example, if a generation unit serves 1,000 MWh of retail load and incurs startup costs, fuel costs, operations costs and maintenance costs totaling $60,000, then the average cost of production is $60 per MWh.

Q. How does Aurora model coal plant dispatch?

A. Consistent with well-established economic principles and standard industry practice, Aurora dispatches coal units based on their incremental (or marginal) cost of production. This approach optimizes the dispatch of the Company's existing system in the most economic, or least-cost, manner while accounting for constraints. If the cost to generate is less than the market price of electricity, the plant is dispatched up. Once the total generation from each plant is known, the total cost of the fuel (including any fixed charges) is spread over the total fuel volume.

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

A. To accurately forecast coal generation costs, the Company models its coal plants to simulate the actual dispatch. The Company excludes from dispatch logic the cost of coal that is subject to take-or-pay provisions.

Q. What are minimum take (or take-or-pay) provisions?

A. As explained in greater detail by Company witness Owen, take-or-pay provisions provide for a minimum payment to be due if PacifiCorp fails to take the minimum contract volume. The Company pays for the full purchase price of fuel due if the annual purchases are below the minimum volume required for a certain timeframe such as a contract year.

Q. How are minimum take provisions modeled in Aurora?

A. Aurora models the minimum take tier as a zero-cost tier for a set level of volume. Incremental prices are modeled as additional tiers over the minimum take tier for those additional volumes. This allows for the model to set an accurate price at which to economically dispatch those units. The minimum take prices are modeled as a pass through that do not affect the economic dispatch of those units.

Q. Is it appropriate to price minimum take levels in Aurora at $0/MMBtu when a CSA has yet to be signed?

A. Yes; as described in further detail in Company witness Owen's testimony, minimum takes are generally a necessary part of the coal contracting process. As a result, in order to ensure an accurate forecast, it is appropriate to include the estimated level of a contractual minimum take when modeling NPC for the test year. This approach is consistent with the modeling the Commission approved in the 2022 TAM.[111]

Q. Is it appropriate to include minimum take requirements at Jim Bridger even though it is partially supplied by Bridger Coal Company (BCC), a Company-owned mine?

A. Yes; as described in further detail in the testimony of Company witness Owen, there are certain fixed costs at BCC that are unavoidable, and the minimum take reflects these costs.

[111] Order No. 21-379 at 11-12.

Q. What are liquidated damages provisions and how are they modeled in Aurora?

A. As explained in greater detail by Company witness Owen, liquidated damages provisions provide for a payment, less than the full price of coal, to be due if PacifiCorp fails to take the minimum contract volume. The Company accounts for liquidated damages in its dispatch analysis by recognizing that these costs will be incurred if the units are not dispatched at contractual minimums.

Q. Has the Commission approved the Company's modeling of minimum take provisions?

A. Yes. As discussed above, in the 2022 TAM, the Commission approved the Company's modeling of minimum take provisions, which was based on the iterative process used in GRID.[112] The transition to Aurora eliminated the need to iteratively determine a dispatch price (which was the focus of controversy last year) but otherwise the Company's modeling in this case is substantively the same as that approved by the Commission last year.

Q. Were there any other coal plant modeling issues raised in the 2022 TAM?

A. Yes. In the 2022 TAM, Sierra Club argued that the Jim Bridger plant was "not subject to a minimum take requirement at Black Butte and the majority of BCC costs are variable" and therefore Sierra Club argued that PacifiCorp should dispatch the Jim Bridger plant using an average cost.[113]

[112] Order No. 21-379 at 12.
[113] Order No. 21-379 at 14.

Q. Did the Commission accept Sierra Club's argument in the 2022 TAM?

A. No. The Commission did not require PacifiCorp to dispatch the Jim Bridger plant using average cost and approved the use of a minimum take volume for Black Butte even though a new CSA had not been signed.

Q. Is the Company's dispatch modeling of the Jim Bridger plant here consistent with the 2022 TAM?

A. Yes. As discussed above, the Company continues to dispatch using the incremental price, not the average price that Sierra Club recommended in the 2022 TAM.

Q. Does Sierra Club again dispute the Company's coal plant dispatch modeling?

A. Yes. Sierra Club once again argues that if the Company were to dispatch using the average price, rather than incremental price, coal generation would decrease:

> 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.[114]

Q. Is this argument substantively the same as the argument Sierra Club made and the Commission rejected in the 2022 TAM?

A. Yes. As described in Company witness Owen's testimony, the Company appropriately accounted for minimum take obligations associated with the new Black Butte CSA and fixed costs associated with BCC production. It would have been

[114] Sierra Club/100, Burgess/44-45.

unrealistic and unreasonable to model Jim Bridger plant coal costs as having no minimum obligations for 2023, contrary to Sierra Club's claims.[115]

Q. What is the basis for Sierra Club's claim that the Company is uneconomically dispatching the Jim Bridger plant?

A. Sierra Club first points to an Aurora run provided as part of the 2023 TAM that dispatched the Jim Bridger plant based on its average cost.

Q. Why did the Company provide the Aurora run that used average costs to dispatch the Jim Bridger plant?

A. In the 2022 TAM, when the Commission rejected Sierra Club's argument to use average cost dispatch, the Commission stated 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 of how the long-term fuel plan could optimize a new Black Butte CSA, the shutdown or conversion of the units, and the level of production at the units by considering the full cost of coal."[116] The study referenced by Sierra Club was therefore provided informationally and does not represent a realistic approach to dispatching the Jim Bridger plant.

Q. Does dispatching the Jim Bridger plant based on the average cost of coal reduce NPC?

A. No. NPC actually increases in the study using average cost dispatch. The following table summarizes the changes resulting from using average cost dispatch at the total-company level.

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[115] *See, e.g.,* Sierra Club/100, Burgess/56.
[116] Order No. 21-379 at 14.

Confidential Table 9

[redacted]

Q. Why does Sierra Club claim that NPC would decrease using average cost dispatch?

A. Sierra Club ignores and eliminates significant fixed costs that will be incurred even in a scenario where the Jim Bridger plant is dispatched using average costs. This is fundamentally the same argument Sierra Club made in the 2022 TAM and Company witness Owen's testimony again explains why Sierra Club's omission of significant fixed costs renders its conclusions incorrect.

Q. Sierra Club's assumptions in its average cost run also require a [redacted] reduction in generation from Jim Bridger driven by lower coal fuel expense.[117] Is this reduction in coal fuel expense possible considering operational constraints and reliability concerns?

A. No. As explained more thoroughly in the testimony of Company witness Owen, BCC cannot operate at a lower capacity and still produce coal at the same dispatch price

[117] Sierra Club/100, Burgess/47.

assumed in the model run because of reduced economies of scale and inefficient use of mine equipment and workforce constraints.

Q. Sierra Club also points to a modeling run provided as part of the Company's 2021 IRP that showed materially lower dispatch of the Jim Bridger plant.[118] Can you provide some background on IRP modeling Sierra Club relies on?

A. Yes. As part of the Commission's review of the 2021 IRP, the Company provided a sensitivity study that removed the minimum take fueling requirements for the Jim Bridger plant. This study was referred to as the "No Minimum Scenario." This approach differed from the 2021 IRP's preferred portfolio, which Sierra Club concedes included minimum take assumptions.[119]

Q. Is Sierra Club's reliance on the No Minimum Scenario reasonable in this case?

A. No. The No Minimum Scenario ignores market realities and does not correctly reflect optimized economic dispatch for the Jim Bridger plant. Indeed, when the Commission acknowledged the Company's 2021 IRP, it noted that "in requiring a no minimum take analysis, we are not suggesting that such a scenario is realistic to carry into operations, given coal supply agreement tradeoffs and coal mine economics[.]"[120] Moreover, the fact that the Commission acknowledged a preferred portfolio that included minimum take assumptions further undermines Sierra Club's reliance on the No Minimum Scenario to suggest that the Company's TAM modeling is deficient or that the Jim Bridger plant is being uneconomically dispatched in the Aurora modeling for 2023.

[118] Sierra Club/100, Burgess/50.
[119] Sierra Club/100, Burgess/50.
[120] *In re PacifiCorp, dba Pac. Power, 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-178 at 7 (May 23, 2022).

It is also important to note that the TAM serves a fundamentally different purpose than PacifiCorp's IRP process and comparisons of the input and output data from the two proceedings is not analogous or appropriate. The purpose of the TAM is to forecast NPC for the coming calendar year using PacifiCorp's existing resources. The IRP is a long-term resource planning process, which has a 20-year planning horizon that considers average coal fuel costs and looks at changes to the Company's generation fleet.

Q. How do the costs of the Jim Bridger plant compare to available alternatives in the 2023 TAM?

A. Based on the March 2022 update to the OFPC, given high gas prices and consequently high market prices, Jim Bridger is deep in the resource stack when ordered from highest price to lowest as illustrated in Confidential Table 10. This table shows that the average price for Jim Bridger is less than all non-coal generation and market alternatives, except the relatively small Blundell geothermal resource.

Confidential Table 10

Resource Name	Direction	Average Price ($/MWh)	Resource Type	Resource Fuel
[redacted]				

[redacted]

C. Jim Bridger Plant Coal Costs

Q. Sierra Club questions the use of estimated costs for the Black Butte CSA that were included in the Company's initial filing.[121] Please explain why the use of estimated fuel costs is appropriate for modeling NPC when actual fuel costs are unavailable.

A. When actual fuel costs per a contract are not yet available, the use of estimated fuel costs is necessary to have a reasonable and prudent NPC forecast for setting rates in the TAM. If a coal unit does not have an executed coal supply agreement at the time of the TAM filing, PacifiCorp uses reasonable proxy fuel cost so those units can be dispatched economically to provide the optimized solution for serving customer load in the forecast while adhering to system constraints. PacifiCorp strives for a forecast that appropriately represents PacifiCorp's system operations within the modeling constraints. In actual operations, PacifiCorp cannot generate energy from a coal unit without paying for the fuel to generate that power. Therefore, to model an accurate dispatch price for the generation costs of that unit, PacifiCorp needs to include the fuel costs for that unit. Since PacifiCorp had not finalized the contract pricing for the Black Butte CSA, the Company had no other option other than to use estimated pricing to develop an NPC forecast. Without including estimated costs, PacifiCorp's forecast would not reflect the operational reality of the costs of generating energy from those units. Not only is this logical, but it is also standard industry practice in order to forecast NPC in a manner that reflects operational reality. PacifiCorp has consistently used estimated costs for CSAs when forecasting NPC in prior TAMs,

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

including the 2022 TAM. Indeed, Sierra Club raised the same argument last year, when it claimed that PacifiCorp improperly assumed it would have a "minimum take with Black Butte for Jim Bridger when that contract [had] not yet been signed."[122]

Q. Are Sierra Club's concerns over the estimated costs of the new Black Butte CSA moot?

A. Yes. As described by Company witness Owen, the Company has now executed the Black Butte CSA and replaced the estimated costs with the actual costs reflected in the agreement.

Q. Sierra Club recommends disallowance of all the fuel costs for Jim Bridger.[123] Is this appropriate?

A. No; this argument is irresponsible and would harm PacifiCorp's customers by causing unnecessary fluctuations in rates. The disallowance of the estimated costs of these contracts would artificially reduce the NPC, resulting in a significant under-collection that would potentially be made up by a larger rate increase in the subsequent PCAM. PacifiCorp strongly opposes Sierra Club's proposal as it would unnecessarily cause significant ups and downs in customer rates for no legitimate regulatory purpose.

Q. Does the removal of these costs as requested by Sierra Club lead to a less accurate NPC forecast?

A. Yes. Sierra Club is not recommending the removal of the generation from those plants (which would significantly increase NPC as described below); they are recommending that the fuel cost for those plants be removed. Essentially Sierra Club

[122] Order No. 21-379 at 11.
[123] Sierra Club/100, Burgess/57-58.

is including no-fuel cost generation from the Jim Bridger plant. This is neither accurate nor consistent with PacifiCorp's operations.

Q. Is it appropriate to remove the costs of operating those units without also removing the generation associated with those units, as recommended by Sierra Club?

A. No, it is not appropriate. This would lead to a fundamental mismatch between the costs and benefits of operating those units. What Sierra Club proposes is nonsensical, because it removes the fuel cost associated with operating those units, while continuing to model the generational benefits from those units. The NPC forecast is not accurate if it artificially lowers NPC through cost-free generation from Jim Bridger. Notably, it would also be nonsensical to exclude the generation from Jim Bridger as it would also artificially increase the NPC forecast.

Q. If PacifiCorp were unable to generate power from Jim Bridger in actual operations, would this impact system reliability?

A. Yes. The removal of this generation means the Company would need to make market purchases to offset the resultant loss of generation. However, there are significant concerns about the availability of the market depth and longer-term resource adequacy in the western United States. There is a strong consensus that the western region is facing an increasing capacity deficit. The Pacific Northwest Resource Adequacy Forum (later replaced by the Resource Adequacy Advisory Committee) issued resource adequacy standards in April 2008, which were subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year, and including only existing resources and planned resources that are already sited and licensed. The assessment issued October 2019 concludes that power supply is expected to be adequate through 2020, with energy and capacity surplus becoming a deficit in 2021 and 2022 at a loss of load probability of 10 percent. The assessment includes approximately 550 megawatts of new capacity scheduled to come online in 2021.

Q. Based on your experience with PacifiCorp's market operations, would PacifiCorp have difficulty replacing lost generation from all of Jim Bridger if it were taken offline for the duration of 2023?

A. Yes. In the event that PacifiCorp would lose the ability to utilize the generation resources of Jim Bridger in 2023, not only would this unplanned outage impose significant financial costs onto the Company's customers, [redacted]

Q. Has PacifiCorp modeled how NPC would be impacted if the costs and generation from Jim Bridger was removed from PacifiCorp's operations?

A. Yes; PacifiCorp modeled the removal of fuel costs and generation from the Jim Bridger plant for calendar year 2023 and it resulted in an increase to net power costs of approximately [redacted] on a total-company basis.

Q. Does the NPC forecast have an indicator that can help assess how certain changes impact system reliability?

A. Yes; there is a modeling construct that is indicated in the NPC report by emergency purchases.

Q. Please explain what emergency purchases are and how they relate to reliability.

A. As discussed above, emergency purchases are simply a modeling construct that allows Aurora to solve instances where the system resources are insufficient to balance generation and load. In Aurora, emergency purchases take place when the model has no other method to satisfy the load obligation because of the modeling constraints, or in rare cases when the emergency purchase price is less than the cost of an alternative solution.[124] Emergency purchases help the model meet its reliability target to ensure there is no unserved load. As emergency purchases increase, it reflects reliability issues that are inconsistent with a feasible operational plan. In other words, emergency purchases are a modeling solution and do not have an equivalent in actual operations. In the event of an actual emergency, PacifiCorp does not have unlimited energy available to purchase to meet load at a reasonable price as

[124] In Aurora, emergency purchases are priced at 125 percent of market and are available to purchase at load. These are conservative assumptions that are unlikely to reflect actual emergency purchase needs from either a cost or availability (market liquidity) perspective.

Aurora assumes. A forecast that includes excessive emergency purchases is strongly indicative of an untenable forecast that cannot be dispatched while maintaining reliability.

Q. How does the removal of the generation from Jim Bridger in the NPC forecast impact emergency purchases?

A. Emergency purchases increased by [redacted] when the Jim Bridger generation was removed, indicating severe lack of available generation to serve customer load.

Q. Sierra Club suggests that there is no minimum take requirement for BCC because it is an affiliate mine and that since the Black Butte contract has not been executed as of the initial filing there is no minimum take for Jim Bridger.[125] Do you agree?

A. Not quite. While BCC does not have a minimum take requirement, it does have fixed costs that are unavoidable over a single forecast period and function like a minimum take requirement in the Company's modeling. Incorporating these fixed costs into Aurora ensures a more accurate NPC and the lowest costs for customers. This modeling is standard procedure for mine contracts and mining operations. Additionally, PacifiCorp has now incorporated the minimum take level reflected in the executed CSA with Black Butte. Company witness Owen explains this in more detail in his testimony.

[125] Sierra Club/100, Burgess/54.

Q. Sierra Club recommends 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 [redacted] MMBtu range.[126] Is this a reasonable recommendation?

A. No. This recommendation is informed by Sierra Club's erroneous claim that it "reflect[s] 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."[127] As described by Company witness Owen, these claims are incorrect.

Q. What is the impact to NPC under the erroneous assumption that Jim Bridger's minimum take volume could be reduced to [redacted] MMBtu?

A. NPC increases by approximately [redacted] on a total-company basis. Please refer to the table below which shows the total-company impact.

Confidential Table 11

[redacted]

[126] Sierra Club/100, Burgess/57.
[127] Sierra Club/100, Burgess/57.

Q. Sierra Club also recommends that if the Commission is inclined to grant recovery for BCC fuel costs in the 2023 TAM, then the costs should, at a minimum, be consistent with PacifiCorp's preferred Scenario 5 of the LTFSP. Sierra Club Claims that in combination with the removal of Black Butte costs, this would reduce the NPC by $111.4 million. The Oregon-allocated portion of the NPC would decrease by approximately $27.9 million, or about 8 percent.[128] Is this a reasonable recommendation?

A. No. Company witness Owen describes why using the LTFSP instead of the updated TAM costs is improper and does not reflect the costs that are expected to be incurred in 2023.

Q. In the alternative, Sierra Club also recommends that the Commission should make clear that any approved rate recovery of these estimated Jim Bridger coal costs is still "at risk" for PacifiCorp pending future Commission review of the final Black Butte CSAs and BCC operating plan.[129] Is this a reasonable recommendation?

A. No; it is unclear to me what this recommendation hopes to accomplish. First, the final Black Butte CSA and supporting analysis has been filed in this docket. Second, this proceeding seeks to produce a reasonable and appropriate forecast for PacifiCorp's NPC for calendar year 2023. In order to do so, PacifiCorp has used a reasonable estimate for coal costs from Black Butte and BCC. Retroactively truing up those estimates with actuals, which is what Sierra Club appears to recommend is

[128] Sierra Club/100, Burgess/58.
[129] Sierra Club/100, Burgess/59.

contrary to the framework of the TAM and appears to be impermissible retroactive ratemaking.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 400
Exhibit PAC/601
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Step Log Change

June 2022

2023 TAM Step Log			
ORTAM23 Initial Filing		$	1,683,929,925
	Corrections		**Impact**
	Regulating Reserve Requirement	$	(16,561,012.37)
	Utah Solar Adjustment	$	(11,387,569.39)
	Updates		
Update 1	OFPC	$	80,081,690.58
Update 2	Market Capacity Update	$	5,575,481.98
Update 3	Short-Term Firm Transactions, Gas Hedges	$	(2,484,941.12)
Update 4	Coal Prices	$	(8,125,178.90)
Update 5	Long Term Contracts and QFs and Wheeling	$	43,331,116.22
Update 6	Short-Term Transmission Links	$	(2,369,331.19)
Update 7	EIM	$	(15,974,782.79)
Update 8	Chehalis Adder	$	19,840,740.20
ORTAM23 Reply Filing		$	1,775,856,138

Docket No. UE 400
Exhibit PAC/602
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Oregon-Allocated Net Power Costs

June 2022

PacifiCorp
CY 2023 TAM
Reply Filing

Line no		ACCT.	Total Company: UE-390 CY 2022 - Final Update	Total Company: TAM CY 2023 - Initial Filing	Total Company: TAM CY 2023 - Reply Filing	Factor	Factors CY 2022	Factors CY 2023 Initial Filing	Factors CY 2023 Reply Filing	Oregon Allocated: UE-390 CY 2022 - Final Update	Oregon Allocated: TAM CY 2023 - Initial Filing	Oregon Allocated: TAM CY 2023 - Reply Filing
1	**Sales for Resale**											
2	Existing Firm PPL	447	8,349,236	6,189,133	6,438,454	SG	26.482%	26.070%	26.002%	2,211,009	1,613,528	1,674,111
3	Existing Firm UPL	447	-	-	-	SG	26.482%	26.070%	26.002%	-	-	-
4	Post-Merger Firm	447	599,533,731	349,419,847	388,137,839	SG	26.482%	26.070%	26.002%	158,765,990	91,094,949	100,922,674
5	Non-Firm	447	-	-	-	SE	25.369%	25.068%	24.920%	-	-	-
6	**Total Sales for Resale**		607,882,968	355,608,980	394,576,293					160,976,999	92,708,477	102,596,785
7												
8	**Purchased Power**											
9	Existing Firm Demand PPL	555	34,174,104	8,295,068	8,263,723	SG	26.482%	26.070%	26.002%	9,049,842	2,162,553	2,148,713
10	Existing Firm Demand UPL	555	12,291,919	11,456,377	12,335,572	SG	26.482%	26.070%	26.002%	3,255,094	2,986,717	3,207,466
11	Existing Firm Energy	555	107,897,352	44,724,911	44,916,482	SE	25.369%	25.068%	24.920%	27,372,866	11,211,701	11,193,250
12	Post-merger Firm	555	717,644,565	885,848,099	938,522,812	SG	26.482%	26.070%	26.002%	190,043,601	230,943,629	244,032,459
13	Secondary Purchases	555	-	-	-	SE	25.369%	25.068%	24.920%	-	-	-
14	Other Generation Expense	555	-	-	-	SG	26.482%	26.070%	26.002%	-	-	-
15	**Total Purchased Power**		872,007,940	950,324,455	1,004,038,588					229,721,403	247,304,600	260,581,889
16												
17	**Wheeling Expense**											
18	Existing Firm PPL	565	23,937,361	23,886,724	23,886,724	SG	26.482%	26.070%	26.002%	6,338,991	6,227,351	6,210,969
19	Existing Firm UPL	565	-	-	-	SG	26.482%	26.070%	26.002%	-	-	-
20	Post-merger Firm	565	115,028,330	124,541,723	124,541,723	SG	26.482%	26.070%	26.002%	30,461,316	32,468,453	32,383,041
21	Non-Firm	565	12,043,742	12,388,361	6,893,033	SE	25.369%	25.068%	24.920%	3,055,420	3,105,531	1,717,753
22	**Total Wheeling Expense**		151,009,433	160,816,807	155,321,479					39,855,727	41,801,335	40,311,763
23												
24	**Fuel Expense**											
25	Fuel Consumed - Coal	501	647,001,159	599,969,137	645,616,919	SE	25.369%	25.068%	24.920%	164,140,043	150,401,074	160,888,638
26	Fuel Consumed - Coal (Cholla)	501	-	-	-	SE	25.369%	25.068%	24.920%	-	-	-
27	Fuel Consumed - Gas	501	7,098,310	13,117,319	17,565,684	SE	25.369%	25.068%	24.920%	1,800,796	3,288,267	4,377,393
28	Natural Gas Consumed	547	292,158,097	301,360,345	330,155,685	SE	25.369%	25.068%	24.920%	74,118,635	75,545,418	82,275,258
29	Simple Cycle Comb. Turbines	547	4,046,151	9,466,735	13,249,969	SE	25.369%	25.068%	24.920%	1,026,483	2,373,134	3,301,911
30	Steam from Other Sources	503	3,966,594	4,484,106	4,484,106	SE	25.369%	25.068%	24.920%	1,006,299	1,124,082	1,117,446
31	**Total Fuel Expense**		954,270,311	928,397,642	1,011,072,364					242,092,255	232,731,975	251,960,645
32												
33	TAM Settlement Adjustment		-	-	-			As Settled		-	-	-
34												
35	**Net Power Cost (Per GRID/Aurora)**		1,369,404,716	1,683,929,924	1,775,856,138					350,692,386	429,129,432	450,257,513
36												
37	Oregon Situs NPC Adustments		(167,224)	(430,221)	2,571,370	OR	100.000%	100.000%	100.000%	(167,224)	(430,221)	2,571,370
38	**Total NPC Net of Adjustments**		1,369,237,492	1,683,499,703	1,778,427,508					350,525,162	428,699,211	452,828,883
39												
40	Production Tax Credit (PTC)		(258,284,914)	(269,231,073)	(269,231,073)	SG	26.482%	26.070%	26.002%	(68,397,920)	(70,189,462)	(70,004,820)
41	**Total TAM Net of Adjustments**		1,110,952,578	1,414,268,630	1,509,196,435					282,127,243	358,509,750	382,824,062
42												
43										Increase Absent Load Change	76,382,507	100,696,819
44												
45									Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-39(	$282,127,243		
46									$ Change due to load variance from UE-390 forecast	6,408,529		
47									2023 Recovery of NPC (incl. PTC) in Rates	$288,535,772		
48												
49										**Increase Including Load Change**	**$ 69,973,978**	**$ 94,288,290**
50												
51										Add Other Revenue Change	-	-
52												
53										**Total TAM Increase/(Decrease)**	**$ 69,973,978**	**$ 94,288,290**

Docket No. UE 400
Exhibit PAC/603
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Net Power Costs Report

June 2022

Exhibit PAC 603 - ORTAM23 Net Power Costs

$

	Total	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ 6,438,454	$ 549,621	$ 486,185	$ 555,919	$ 510,775	$ 538,340	$ 507,675	$ 570,767	$ 571,880	$ 535,153	$ 520,685	$ 515,121	$ 576,332
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	6,561	547	547	547	547	547	547	547	547	547	547	547	547
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	215,587	15,478	14,746	16,009	8,357	9,773	13,111	35,803	35,734	25,487	14,851	12,004	14,235
PSCo Sale	13,112,861	894,040	824,640	910,380	653,600	677,440	881,920	1,839,220	2,216,455	2,092,288	719,881	700,412	702,586
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	19,773,462	1,459,686	1,326,117	1,482,855	1,173,279	1,226,100	1,403,253	2,446,337	2,824,615	2,653,475	1,255,964	1,228,083	1,293,699
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	2,932,200	1,083,150	977,400	871,650	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	2,932,200	1,083,150	977,400	871,650	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	73,913,456	8,138,330	6,807,483	3,895,140	2,821,449	3,969,693	4,384,513	6,699,601	6,023,799	7,921,304	7,507,206	8,096,647	7,648,292
Four Corners	76,984,777	16,651,517	14,556,798	9,315,677	1,324,884	2,781,396	7,041,874	8,180,290	4,515,015	9,898,282	8,983,384	1,414,828	(7,679,168)
Mead	41,170,509	4,369,985	2,435,609	3,281,657	1,586,955	2,340,274	5,550,659	4,414,949	3,698,437	6,909,608	3,357,813	2,246,902	977,661
Mid Columbia	117,368,571	8,154,592	3,401,999	590,821	2,037,588	3,247,344	5,794,197	16,265,767	22,623,777	17,398,672	10,855,429	10,464,648	16,533,737
Mona	34,295,857	7,105,917	3,591,040	2,411,309	736,546	876,080	2,233,312	2,225,221	3,315,650	4,546,663	3,183,694	2,212,480	1,857,946
NOB	15,526,188	982,613	1,235,116	1,197,686	818,171	414,747	1,477	2,022,824	2,857,545	1,914,324	1,120,331	1,443,105	1,518,250
Palo Verde	8,990,117	702,882	368,355	780,430	461,370	525,522	480,688	1,729,122	229,401	2,067,290	867,535	638,652	138,868
Palo Verde - PSCO Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	3,621,156	464,583	126,620	51,183	5,047	399,402	308,775	807,277	479,545	405,124	182,853	199,188	191,558
Total System Balancing Sales	371,870,630	46,570,420	32,523,019	21,523,904	9,792,011	14,554,457	25,795,495	42,345,052	43,743,170	51,061,266	36,058,244	26,716,449	21,187,145
Total Special Sales For Resale	394,576,293	49,113,256	34,826,537	23,878,409	10,965,289	15,780,557	27,198,748	44,791,388	46,567,784	53,714,741	37,314,208	27,944,532	22,480,844
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Appaloosa 1A Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Appaloosa 1B Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Castle Solar UoU	-	-	-	-	-	-	-	-	-	-	-	-	-
Castle Solar IHC	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,272	1,348,848	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,094	1,025,293	832,068	784,236	772,111	631,272	565,348	564,366	445,199	628,829	828,668	811,823	1,018,881

Combine Hills Wind	5,518,680	391,582	474,473	577,295	573,395	489,246	422,189	470,712	401,146	374,581	392,359	478,127	473,577
Cove Mountain Solar	3,833,283	183,848	193,154	336,688	366,527	421,871	453,707	440,109	416,435	357,107	287,471	206,551	169,814
Cove Mountain Solar II	9,492,755	455,531	478,588	834,231	908,164	1,045,294	1,124,175	1,090,482	1,031,823	884,823	712,282	508,940	418,421
Deseret Purchase	35,888,318	3,117,461	2,949,508	2,955,015	2,765,034	2,776,048	2,621,861	3,142,241	3,142,241	3,109,201	3,142,241	3,052,758	3,114,708
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	-	-	-	-	-	-	-	-	-	-	-	-	-
Elektron Solar 20 yr	-	-	-	-	-	-	-	-	-	-	-	-	-
Elektron Solar 25yr	-	-	-	-	-	-	-	-	-	-	-	-	-
Gemstate	1,145,216	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	-	-	-	-
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Graphite Solar	6,272,497	313,766	355,437	561,331	616,028	690,923	708,977	691,500	646,870	579,734	483,379	357,284	267,268
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Horseshoe Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter Solar	7,051,153	371,168	420,781	641,039	669,033	762,896	789,454	750,512	705,507	657,834	561,379	398,161	323,388
Hurricane Purchase	185,380	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	3,837,570	320,800	312,780	316,790	324,810	316,790	324,810	328,820	312,780	308,770	296,740	344,860	328,820
Milican Solar	2,814,730	92,708	141,477	216,779	272,858	323,854	352,508	396,975	350,779	282,304	184,848	118,394	81,245
Milford Solar	6,975,304	353,274	406,820	600,085	667,481	784,725	827,371	736,808	709,314	661,660	533,619	388,227	305,919
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	20,600,000	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,875,216	63,645	97,125	144,022	181,280	215,160	234,197	263,740	233,048	187,556	122,808	78,658	53,977
Rock River Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rocket Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Sigurd Solar	5,917,296	309,554	345,619	509,742	556,548	639,667	703,042	653,634	599,181	559,401	453,931	319,006	267,971
Skysol Solar	9,192,400	-	-	698,731	756,489	964,767	1,278,104	1,603,572	1,541,676	1,061,102	626,170	344,706	317,083
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,712,516	2,790,662	1,806,920	2,141,628	1,609,251	1,428,678	1,205,304	804,843	950,802	1,185,464	1,741,196	2,346,698	2,701,069
Top of the World Wind	40,663,534	5,436,528	3,612,747	4,245,733	3,266,227	2,910,525	2,398,843	1,719,857	1,873,298	2,296,246	3,519,349	4,486,125	4,898,057
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,515,791	779,175	910,409	1,160,071	1,067,046	809,392	861,546	685,959	655,309	770,017	851,206	983,388	982,273
UT Solar Adjustment	(15,765,252)	(769,297)	(834,025)	(1,395,562)	(1,524,192)	(1,736,217)	(1,833,152)	(1,781,983)	(1,678,693)	(1,464,556)	(1,195,661)	(866,224)	(685,690)
Long Term Firm Purchases Total	204,656,627	19,068,037	16,082,612	18,843,584	17,347,612	16,789,265	16,265,683	15,788,473	15,406,223	15,607,886	16,972,841	17,766,197	18,718,213
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities													
QF California	1,949,463	167,498	177,630	211,597	215,520	201,586	163,935	139,039	134,406	127,305	131,831	130,101	149,015
QF Idaho	8,053,629	630,421	621,030	669,633	674,163	679,953	677,814	733,869	667,907	614,562	647,635	656,520	780,122
QF Oregon	45,004,001	2,272,070	2,687,047	3,683,085	4,742,933	5,055,112	5,357,951	5,183,599	4,928,305	4,109,928	3,012,556	2,019,032	1,952,384
QF Utah	12,465,631	852,212	891,894	1,078,846	1,105,629	1,216,055	1,236,570	1,149,183	1,147,019	1,075,785	1,012,884	890,675	808,880
QF Washington	214,683	-	-	-	5,120	18,598	51,806	58,266	53,533	25,617	1,742	-	-
QF Wyoming	96,851	8,180	8,841	12,131	6,897	4,745	2,535	9,505	9,015	4,847	6,879	8,471	14,805
Biomass One QF	17,682,382	1,579,705	1,323,820	1,494,894	1,660,178	1,717,172	1,669,902	1,492,952	1,480,105	1,422,906	1,521,916	1,485,941	832,891
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	185,527	5,694	5,499	3,583	2,579	3,094	6,717	32,995	45,670	44,522	18,113	8,561	8,501
Enterprise Solar I QF	12,352,091	610,749	742,267	965,709	1,095,701	1,238,554	1,358,555	1,512,798	1,490,493	1,160,459	944,327	695,736	536,743
Escalante Solar I QF	11,404,022	560,006	669,967	869,548	997,539	1,175,746	1,287,172	1,398,773	1,375,284	1,074,225	860,392	634,462	500,909
Escalante Solar II QF	10,735,377	526,167	628,933	819,242	937,921	1,111,824	1,216,605	1,322,724	1,291,428	1,012,439	806,961	593,628	467,505
Escalante Solar III QF	10,341,613	512,290	614,790	795,035	912,809	1,083,235	1,187,283	1,286,093	1,255,349	984,296	738,642	544,017	427,775
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-

Five Pine Wind QF	9,021,830	550,461	910,272	806,702	853,690	522,219	575,763	675,805	643,960	805,777	800,069	937,020	940,093
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,735,682	542,663	606,878	882,292	972,645	1,141,845	1,237,607	1,309,167	1,249,670	961,810	797,580	573,430	460,094
Granite Mountain West Solar QF	7,105,147	359,045	401,777	584,928	644,362	756,525	818,559	867,093	825,673	635,902	527,168	379,923	304,193
Iron Springs Solar QF	11,020,270	627,251	653,455	884,002	997,903	1,114,563	1,262,671	1,319,674	1,305,928	988,606	803,984	570,609	491,624
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,653,969	1,002,787	916,507	1,120,639	895,224	864,180	755,742	667,602	567,897	623,219	795,200	708,251	736,720
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,925,025	1,393,376	1,045,925	866,003	681,385	484,114	500,590	411,924	441,353	469,289	677,879	902,060	1,051,128
Mountain Wind 2 QF	13,915,538	2,031,769	1,567,589	1,351,623	1,063,844	758,044	898,954	763,377	735,213	776,297	1,016,122	1,400,570	1,552,135
North Point Wind QF	20,178,389	1,156,036	1,961,106	1,799,285	1,917,085	1,165,782	1,305,519	1,568,381	1,594,337	1,915,585	1,859,066	1,991,105	1,945,101
Oregon Wind Farm QF	12,447,066	716,938	969,731	1,111,800	1,303,200	1,247,048	1,234,482	1,241,162	1,128,038	927,737	733,410	797,174	1,036,346
Pavant II Solar QF	4,765,170	186,479	235,238	366,263	438,365	499,083	545,808	634,302	631,532	450,777	345,921	239,878	191,526
Pioneer Wind Park I QF	11,487,632	1,307,202	927,042	1,298,761	1,017,770	682,100	734,389	850,534	826,139	541,252	870,246	1,349,003	1,083,195
Power County North Wind QF	5,877,495	447,311	592,810	566,287	552,722	383,638	375,783	396,238	395,677	407,429	548,734	563,861	647,004
Power County South Wind QF	5,236,544	395,001	522,148	510,902	513,013	331,320	334,501	350,551	368,787	360,745	480,238	508,596	560,743
Roseburg Dillard QF	1,278,446	59,044	130,556	65,605	103,400	129,189	78,072	246,922	173,632	74,303	76,449	77,115	64,159
Sage I Solar QF	2,243,423	79,705	78,928	187,861	203,039	233,053	259,536	331,713	331,792	206,029	153,821	103,600	74,348
Sage II Solar QF	2,245,841	79,789	79,021	188,061	203,258	233,267	259,829	332,067	332,160	206,263	153,978	103,728	74,419
Sage III Solar QF	1,848,201	67,187	65,762	155,157	165,491	191,023	212,279	270,704	270,549	170,042	129,039	87,807	63,160
Spanish Fork Wind 2 QF	2,832,096	225,746	182,541	209,510	164,768	158,208	220,711	296,651	324,158	279,769	247,575	257,202	265,257
Sunnyside QF	21,978,257	2,577,595	2,365,459	2,701,136	2,315,995	2,840,431	3,039,203	3,061,643	3,076,795	-	-	-	-
Sweetwater Solar QF	7,672,369	255,091	368,749	557,947	676,497	804,030	969,793	1,098,050	1,027,809	802,870	618,001	295,309	198,224
Tesoro QF	443,146	78,413	58,137	46,539	26,695	37,564	7,070	18,241	31,391	15,921	14,572	19,299	89,303
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,357,581	410,917	470,189	619,669	821,295	852,465	901,100	1,026,396	996,590	784,948	664,925	440,537	368,551
Utah Pavant Solar QF	7,238,041	269,622	314,200	538,516	631,865	757,014	843,216	959,499	913,508	764,023	588,085	363,749	294,746
Utah Red Hills Solar QF	11,335,615	481,754	612,345	778,205	1,015,644	1,181,457	1,213,699	1,480,794	1,438,074	1,292,130	799,312	583,575	458,627
Qualifying Facilities Total	328,328,044	23,026,174	24,408,083	28,800,994	30,536,143	30,873,835	32,801,719	34,498,285	33,509,175	26,117,615	23,405,250	20,920,546	19,430,224
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,308,252	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354
Grant - Priest Rapids	-												
Mid-Columbia Contracts Total	2,308,252	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354	192,354
Total Long Term Firm Purchases	535,292,923	42,286,565	40,683,050	47,836,933	48,076,110	47,855,455	49,259,757	50,479,112	49,107,753	41,917,855	40,570,446	38,879,098	38,340,791
Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-

Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	15,223,600	560,000	537,600	604,800	-	-	-	4,390,000	4,741,200	4,390,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	15,223,600	560,000	537,600	604,800	-	-	-	4,390,000	4,741,200	4,390,000	-	-	-
System Balancing Purchases													
COB	37,722,270	(25,160)	71,233	(125,163)	(344,063)	(251,561)	(379,669)	18,882,131	13,928,636	3,115,480	469,082	228,308	2,153,018
Four Corners	21,906,993	1,888,084	2,176,051	2,187,910	821,403	305,725	384,404	2,336,282	1,834,291	2,274,732	2,147,152	3,021,849	2,529,110
Mead	14,513,873	1,150,163	1,277,106	319,459	621,929	613,493	1,057,463	2,102,844	2,298,366	2,462,911	971,978	1,074,963	563,200
Mid Columbia	345,263,252	2,913,979	1,843,900	1,237,740	1,302,033	1,584,390	6,111,755	74,864,482	102,158,652	58,418,168	25,071,595	20,858,052	48,898,507
Mona	12,582,407	2,620,199	1,204,320	1,610,040	434,236	748,360	346,310	116,109	1,619,715	1,197,925	752,366	1,044,481	888,346
NOB	71,244,302	3,127,053	2,836,750	2,547,344	1,371,357	851,516	2,732	17,592,202	16,437,410	10,998,598	2,963,041	5,553,015	6,963,284
Palo Verde	6,550,232	402,553	106,259	1,396,971	561,774	591,381	322,037	807,967	60,154	988,558	812,209	398,934	101,436
EIM Imports/Exports	(108,046,713)	(11,546,513)	(9,575,028)	(7,335,438)	(4,858,258)	(5,042,951)	(6,800,242)	(15,212,314)	(16,163,193)	(12,762,632)	(6,155,838)	(5,842,580)	(6,751,726)
Emergency Purchases	51,785,448	-	-	-	-	-	-	23,365,878	19,123,242	4,446,285	2,175,241	546,030	2,128,771
Total System Balancing Purchases	453,522,065	530,358	(59,409)	1,838,862	(89,589)	(599,650)	1,044,790	124,855,582	141,297,273	71,140,024	29,206,827	26,883,052	57,473,946
Total Purchased Power & Net Interchange	##########	43,376,923	41,161,241	50,280,595	47,986,521	47,255,805	50,304,546	179,724,694	195,146,226	117,447,879	69,777,272	65,762,149	95,814,737
Wheeling & U. of F. Expense													
Firm Wheeling	152,719,741	13,070,971	12,660,013	12,928,783	12,931,298	12,201,130	13,907,180	12,754,269	12,678,660	12,432,496	12,415,111	12,238,770	12,501,060
C&T EIM Admin fee	2,601,738	184,546	167,911	199,738	189,282	216,532	228,355	235,464	256,292	228,219	226,374	224,006	245,016
ST Firm & Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Wheeling & U. of F. Expense	155,321,479	13,255,518	12,827,924	13,128,521	13,120,581	12,417,663	14,135,535	12,989,732	12,934,952	12,660,715	12,641,486	12,462,776	12,746,077
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	19,954,208	2,251,663	1,992,814	1,904,808	1,341,589	2,128,679	2,118,676	1,556,843	1,769,864	1,534,915	577,665	1,383,386	1,393,307
Craig	23,194,373	2,186,566	1,784,229	1,713,716	1,228,032	2,111,764	2,067,602	1,863,837	2,260,906	2,049,596	2,064,998	1,850,200	2,012,926
Dave Johnston	67,104,688	7,197,731	6,486,571	6,419,433	6,177,807	7,132,652	6,887,280	4,207,208	5,005,731	4,405,552	5,259,907	3,614,563	4,310,255
Hayden	10,209,108	980,548	808,775	836,209	792,764	977,648	875,031	930,211	783,947	885,260	649,039	925,869	763,805
Hunter	137,092,516	14,401,151	12,965,344	7,904,745	10,299,807	14,015,749	14,351,510	10,881,229	10,865,447	9,602,071	11,079,264	11,270,993	9,455,206
Huntington	120,134,936	12,468,035	11,188,872	12,146,311	10,961,004	11,240,234	11,773,770	9,429,924	10,684,664	6,416,155	5,766,212	8,776,022	9,283,734
Jim Bridger	201,228,966	18,045,430	14,700,139	15,755,283	9,641,646	8,610,707	11,542,743	21,448,762	22,143,587	19,783,143	19,842,133	19,636,013	20,079,380
Naughton	32,871,918	2,979,797	2,851,502	2,326,786	2,572,680	2,138,751	2,695,977	3,051,797	3,258,939	2,939,465	3,128,518	2,322,495	2,605,210
Wyodak	33,826,206	3,525,893	3,208,735	3,507,195	3,310,271	3,494,373	3,343,460	2,730,480	2,598,278	2,355,267	2,602,737	1,831,542	1,317,975
Total Coal Fuel Burn Expense	645,616,919	64,036,813	55,986,981	52,514,486	46,325,600	51,850,559	55,656,049	56,100,291	59,371,363	49,971,425	50,970,472	51,611,084	51,221,796
Gas Fuel Burn Expense													
Chehalis	59,574,169	11,053,603	3,288,751	2,191,398	-	-	1,007,241	6,039,910	5,724,626	6,263,639	9,005,431	7,952,820	7,046,750
Currant Creek	74,516,315	8,994,734	5,685,516	6,289,325	6,240,256	4,513,715	6,789,443	9,305,291	6,929,229	6,158,982	3,502,706	5,380,565	4,726,554
Gadsby	17,565,684	1,961,437	1,273,625	951,332	640,978	581,110	752,338	1,745,394	2,164,612	1,984,017	1,363,026	1,730,192	2,417,623
Gadsby CT	13,249,969	1,679,051	1,541,683	1,218,376	472,431	102,211	380,304	1,204,193	1,386,873	1,181,451	1,102,187	1,361,102	1,620,105
Hermiston	35,073,753	6,300,651	4,560,044	3,747,884	2,766,999	2,873,633	2,499,492	1,921,996	1,888,275	2,041,206	950,259	2,237,271	3,286,044
Lake Side 1	83,540,497	8,402,049	7,341,246	7,462,344	6,175,417	5,971,374	6,133,535	7,777,222	7,986,787	7,276,619	4,493,883	7,368,853	7,151,167
Lake Side 2	65,438,898	6,083,080	4,494,702	4,318,878	2,361,756	64,192	3,508,989	7,494,285	7,947,456	7,324,029	6,590,617	6,610,806	8,640,108
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	26,730,826	1,930,031	1,436,503	2,065,860	594,864	833,898	1,281,959	2,940,076	3,017,862	1,961,450	2,365,153	2,245,133	6,058,037

Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	375,690,111	46,404,636	29,622,070	28,245,398	19,252,701	14,940,133	22,353,302	38,428,367	37,045,720	34,191,392	29,373,262	34,886,743	40,946,388
Gas Physical	(4,287,892)	-	-	-	-	(683,180)	(668,437)	(734,848)	(743,483)	(715,186)	(742,759)	-	-
Gas Swaps	(50,230,977)	(10,692,675)	(8,991,990)	(4,488,815)	(296,250)	(47,275)	(166,500)	(3,778,947)	(4,123,930)	(4,143,285)	(1,986,480)	(4,500,150)	(7,014,680)
Clay Basin Gas Storage	(452,163)	(251,165)	(212,897)	(82,892)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(98,940)	(171,968)
Pipeline Reservation Fees	40,252,259	3,403,999	3,284,434	3,371,979	3,292,844	3,287,719	3,298,684	3,398,569	3,395,852	3,356,970	3,400,693	3,362,491	3,398,024
Total Gas Fuel Burn Expense	360,971,338	38,864,795	23,701,618	27,045,670	22,301,538	17,549,639	24,869,291	37,365,384	35,626,402	32,742,134	30,096,958	33,650,144	37,157,764
Other Generation													
Blundell	4,484,106	461,755	417,069	461,755	362,477	432,185	418,243	381,550	390,298	406,476	346,843	229,062	176,392
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-	-	-	-	-	-	-	-	-	-	-	-	-
Dunlap I Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Ekola Flats Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Foote Creek I Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Glenrock Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Glenrock III Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Goodnoe Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
High Plains Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Marengo I Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Marengo II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Pryor Mountain Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Cap Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
TB Flats Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
TB Flats Wind II	-	-	-	-	-	-	-	-	-	-	-	-	-
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	4,484,106	461,755	417,069	461,755	362,477	432,185	418,243	381,550	390,298	406,476	346,843	229,062	176,392
Net Power Cost	**1,775,856,138**	**110,882,548**	**99,268,297**	**119,552,618**	**119,131,427**	**113,725,293**	**118,184,917**	**241,770,263**	**256,901,456**	**159,513,888**	**126,518,824**	**135,770,684**	**174,635,922**
Net Power Cost/Net System Load	28.73	20.58	20.88	24.13	25.46	23.43	22.73	41.06	44.80	31.98	26.03	27.23	31.64

REDACTED
Docket No. UE 400
Exhibit PAC/604
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

GRID Coal Cost Tier Spread

June 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 400
Exhibit PAC/605
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Effects of Ambient Temperature on Generation Output

June 2022

REDACTED

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REDACTED

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GER-3567H

GE Power Systems

GE Gas Turbine Performance Characteristics

Frank J. Brooks
GE Power Systems
Schenectady, NY

GE Gas Turbine Performance Characteristics

Contents

GE Gas Turbine Performance Characteristics

GE Gas Turbine Performance Characteristics

Introduction

GE offers both heavy-duty and aircraft-derivative gas turbines for power generation and industrial applications. The heavy-duty product line consists of five different model series: MS3002, MS5000, MS6001, MS7001 and MS9001.

The MS5000 is designed in both single- and two-shaft configurations for both generator and mechanical-drive applications. The MS5000 and MS6001 are gear-driven units that can be applied in 50 Hz and 60 Hz markets.

All units larger than the Frame 6 are direct-drive units. The MS7000 series units that are used for 60 Hz applications have rotational speeds of 3600 rpm. The MS9000 series units used for 50 Hz applications have a rotational speed of 3000 rpm. In generator-drive applications the product line covers a range from approximately 35,800 hp to 345,600 hp (26,000 kW to 255,600 kW).

Table 1 provides a complete listing of the available outputs and heat rates of the GE heavy-duty gas turbines. *Table 2* lists the ratings of mechanical-drive units, which range from 14,520 hp to 108,990 hp (10,828 kW to 80,685 kW).

The complete model number designation for each heavy-duty product line machine is provided in both *Tables 1 and 2*. An explanation of the model number is given in *Figure 1*.

This paper reviews some of the basic thermodynamic principles of gas turbine operation and explains some of the factors that affect its performance.

GE Generator Drive Product Line

Model	Fuel	ISO Base Rating (kW)	Heat Rate (Btu/kWh)	Heat Rate (kJ/kWh)	Exhaust Flow (lb/hr) $x10^{-3}$	Exhaust Flow (kg/hr) $x10^{-3}$	Exhaust Temp (degrees F)	Exhaust Temp (degrees C)	Pressure Ratio
PG5371 (PA)	Gas	26,070.	12,060.	12,721	985.	446	905.	485	10.6
	Dist.	25,570.	12,180.	12,847	998.	448	906.	486	10.6
PG6581 (B)	Gas	42,100.	10,640.	11,223	1158.	525	1010.	543	12.2
	Dist.	41,160.	10,730.	11,318	1161.	526	1011.	544	12.1
PG6101 (FA)	Gas	69,430.	10,040.	10,526	1638.	742	1101.	594	14.6
	Dist.	74,090.	10,680.	10,527	1704.	772	1079.	582	15.0
PG7121 (EA)	Gas	84,360.	10,480.	11,054	2361.	1070	998.	536	12.7
	Dist.	87,220.	10,950.	11,550	2413.	1093	993.	537	12.9
PG7241 (FA)	Gas	171,700.	9,360.	9,873	3543.	1605	1119.	604	15.7
	Dist.	183,800.	9,965.	10,511	3691.	1672	1095.	591	16.2
PG7251 (FB)	Gas	184,400.	9,245.	9,752	3561.	1613	1154.	623	18.4
	Dist.	177,700.	9,975.	10,522	3703.	1677	1057.	569	18.7
PG9171 (E)	Gas	122,500.	10,140.	10,696	3275.	1484	1009.	543	12.6
	Dist.	127,300.	10,620.	11,202	3355.	1520	1003.	539	12.9
PG9231 (EC)	Gas	169,200.	9,770.	10,305	4131.	1871	1034.	557	14.4
	Dist.	179,800.	10,360.	10,928	4291.	1944	1017.	547	14.8
PG9351 (FA)	Gas	255,600.	9,250.	9,757	5118.	2318	1127.	608	15.3
	Dist.	268,000.	9,920.	10,464	5337.	2418	1106.	597	15.8

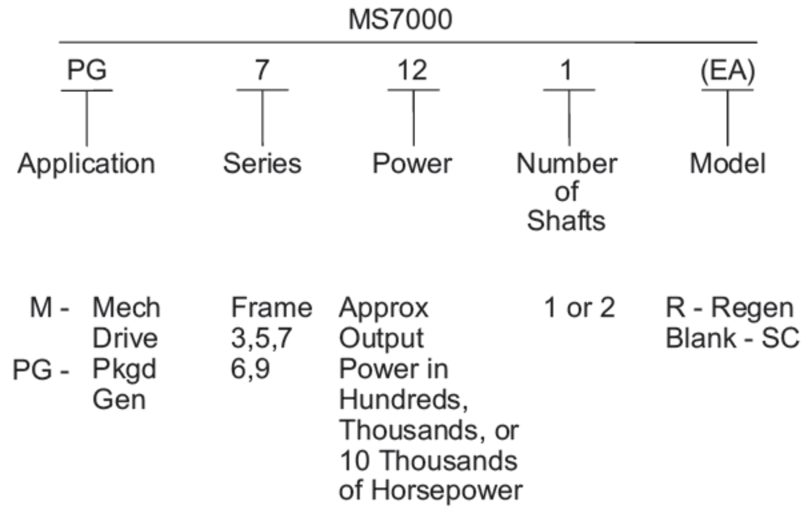
GT22043E

Table 1. GE gas turbine performance characteristics - Generator drive gas turbine ratings

GE Gas Turbine Performance Characteristics

Mechanical Drive Gas Turbine Ratings									
Model	Year	ISO Rating Continuous (kW)	ISO Rating Continuous (hp)	Heat Rate (Btu/shp-hr)	Heat Rate (kJ/kWh)	Mass Flow (lb/sec)	Mass Flow (kg/sec)	Exhaust Temp (degrees F)	Exhaust Temp (degrees C)
M3142 (J)	1952	11,290	15,140	9,500	13,440	117	53	1,008	542
M3142R (J)	1952	10,830	14,520	7,390	10,450	117	53	698	370
M5261 (RA)	1958	19,690	26,400	9,380	13,270	205	92	988	531
M5322R (B)	1972	23,870	32,000	7,070	10,000	253	114	666	352
M5352 (B)	1972	26,110	35,000	8,830	12,490	273	123	915	491
M5352R (C)	1987	26,550	35,600	6,990	9,890	267	121	693	367
M5382 (C)	1987	28,340	38,000	8,700	12,310	278	126	960	515
M6581 (B)	1978	38,290	51,340	7,820	11,060	295	134	1,013	545

Table 2. GE gas turbine performance characteristics - Mechanical drive gas turbine ratings GT25385A



GT23054A

Figure 1. Heavy-duty gas turbine model designation

Thermodynamic Principles

A schematic diagram for a simple-cycle, single-shaft gas turbine is shown in *Figure 2*. Air enters the axial flow compressor at point 1 at ambient conditions. Since these conditions vary from day to day and from location to location, it is convenient to consider some standard conditions for comparative purposes. The standard conditions used by the gas turbine industry are 59 F/15 C, 14.7 psia/1.013 bar and 60% relative humidity, which are established by the International Standards Organization (ISO) and frequently referred to as ISO conditions.

Air entering the compressor at point 1 is compressed to some higher pressure. No heat is added; however, compression raises the air temperature so that the air at the discharge of the compressor is at a higher temperature and pressure.

Upon leaving the compressor, air enters the combustion system at point 2, where fuel is injected and combustion occurs. The combustion process occurs at essentially constant pressure. Although high local temperatures are reached within the primary combustion zone (approaching stoichiometric conditions), the

GE Gas Turbine Performance Characteristics

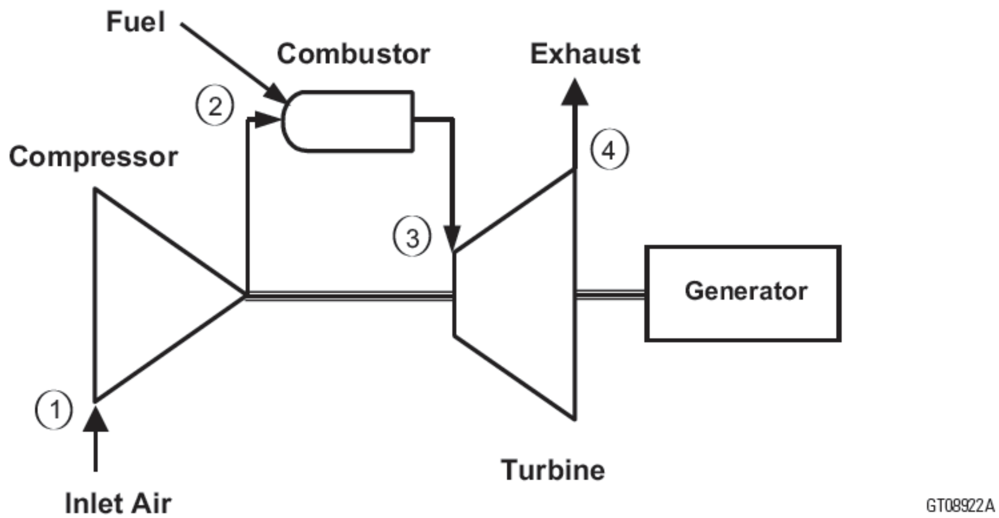


Figure 2. Simple-cycle, single-shaft gas turbine

combustion system is designed to provide mixing, burning, dilution and cooling. Thus, by the time the combustion mixture leaves the combustion system and enters the turbine at point 3, it is at a mixed average temperature.

In the turbine section of the gas turbine, the energy of the hot gases is converted into work. This conversion actually takes place in two steps. In the nozzle section of the turbine, the hot gases are expanded and a portion of the thermal energy is converted into kinetic energy. In the subsequent bucket section of the turbine, a portion of the kinetic energy is transferred to the rotating buckets and converted to work.

Some of the work developed by the turbine is used to drive the compressor, and the remainder is available for useful work at the output flange of the gas turbine. Typically, more than 50% of the work developed by the turbine sections is used to power the axial flow compressor.

As shown in *Figure 2*, single-shaft gas turbines are configured in one continuous shaft and, therefore, all stages operate at the same speed. These units are typically used for generator-drive applications where significant speed variation is not required.

A schematic diagram for a simple-cycle, two-shaft gas turbine is shown in *Figure 3*. The low-pressure or power turbine rotor is mechanically separate from the high-pressure turbine and compressor rotor. The low pressure rotor is said to be aerodynamically coupled. This unique feature allows the power turbine to be operated at a range of speeds and makes two-shaft gas turbines ideally suited for variable-speed applications.

All of the work developed by the power turbine is available to drive the load equipment since the work developed by the high-pressure turbine supplies all the necessary energy to drive the compressor. On two-shaft machines the starting requirements for the gas turbine load train are reduced because the load equipment is mechanically separate from the high-pressure turbine.

The Brayton Cycle

The thermodynamic cycle upon which all gas turbines operate is called the Brayton cycle. *Figure 4* shows the classical pressure-volume (PV) and temperature-entropy (TS) diagrams for this cycle. The numbers on this diagram cor-

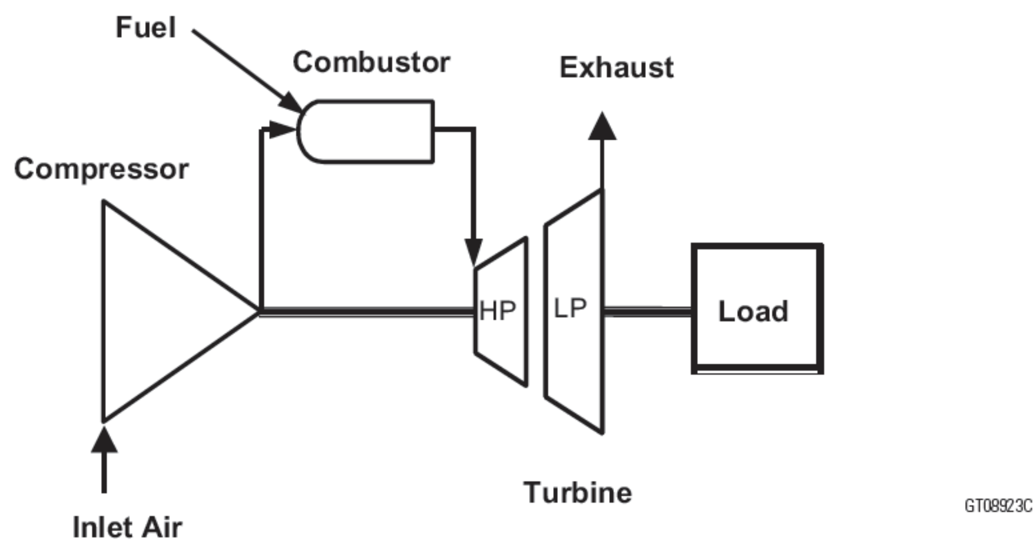


Figure 3. Simple-cycle, two-shaft gas turbine

respond to the numbers also used in *Figure 2*. Path 1 to 2 represents the compression occurring in the compressor, path 2 to 3 represents the constant-pressure addition of heat in the combustion systems, and path 3 to 4 represents the expansion occurring in the turbine.

The path from 4 back to 1 on the Brayton cycle diagrams indicates a constant-pressure cooling process. In the gas turbine, this cooling is done by the atmosphere, which provides fresh, cool air at point 1 on a continuous basis in exchange for the hot gases exhausted to the atmosphere at point 4. The actual cycle is an "open" rather than "closed" cycle, as indicated.

Every Brayton cycle can be characterized by two significant parameters: pressure ratio and firing temperature. The pressure ratio of the cycle is the pressure at point 2 (compressor discharge pressure) divided by the pressure at point 1 (compressor inlet pressure). In an ideal cycle,

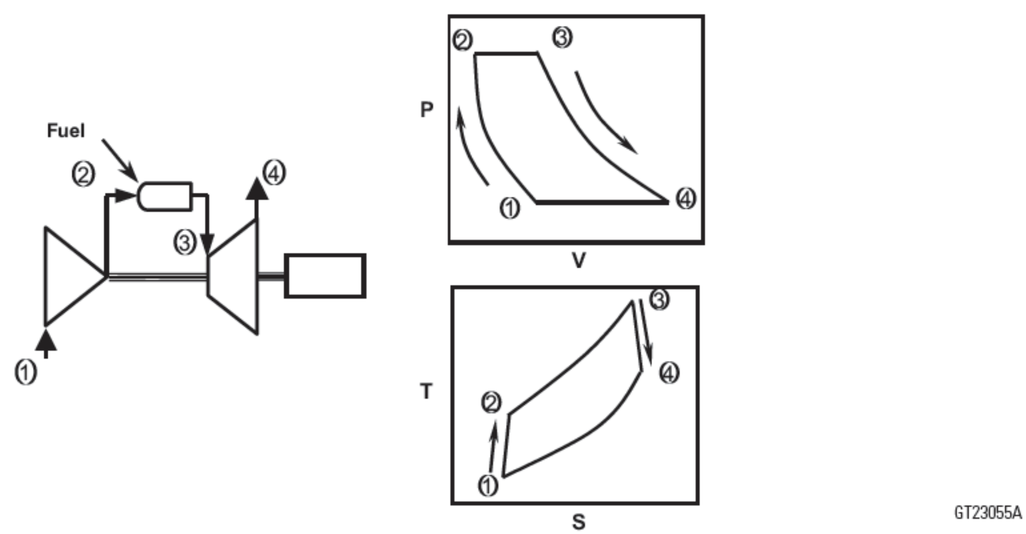


Figure 4. Brayton cycle

this pressure ratio is also equal to the pressure at point 3 divided by the pressure at point 4. However, in an actual cycle there is some slight pressure loss in the combustion system and, hence, the pressure at point 3 is slightly less than at point 2.

The other significant parameter, firing temperature, is thought to be the highest temperature reached in the cycle. GE defines firing temperature as the mass-flow mean total temperature at the stage 1 nozzle trailing edge plane. Currently all first stage nozzles are cooled to keep the temperatures within the operating limits of the materials being used. The two types of cooling currently employed by GE are air and steam.

Air cooling has been used for more than 30 years and has been extensively developed in aircraft engine technology, as well as the latest family of large power generation machines. Air used for cooling the first stage nozzle enters the hot gas stream after cooling down the nozzle and reduces the total temperature immediately downstream. GE uses this temperature since it is more indicative of the cycle temperature represented as firing temperature by point 3 in *Figure 4*.

Steam-cooled first stage nozzles do not reduce the temperature of the gas directly through mixing because the steam is in a closed loop. As shown in *Figure 5*, the firing temperature on a turbine with steam-cooled nozzles (GE's current "H" design) has an increase of 200 degrees without increasing the combustion exit temperature.

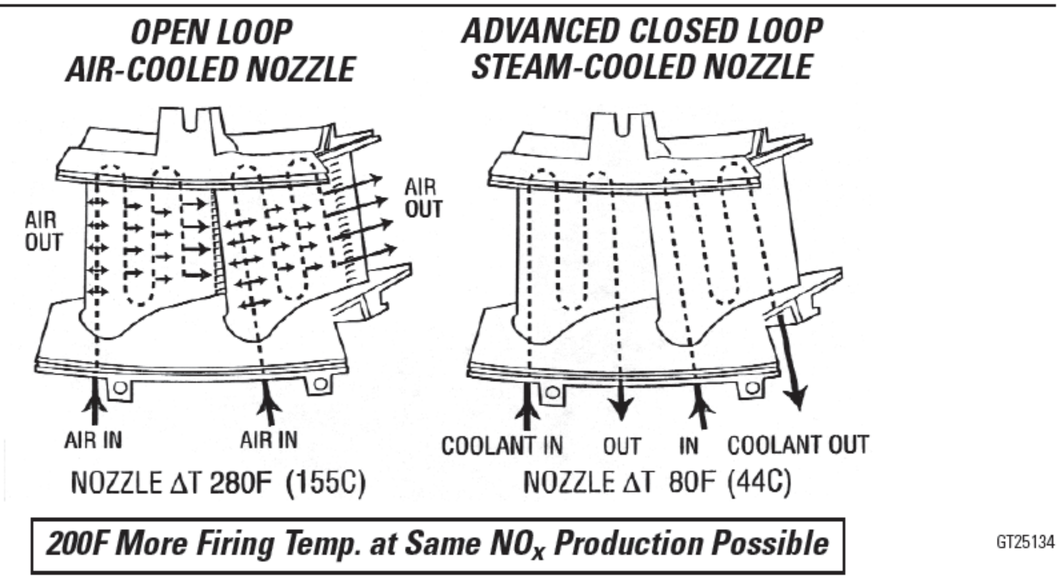


Figure 5. Comparison of air-cooled vs. steam-cooled first stage nozzle

An alternate method of determining firing temperature is defined in ISO document 2314, "Gas Turbines – Acceptance Tests." The firing temperature here is a reference turbine inlet temperature and is not generally a temperature that exists in a gas turbine cycle; it is calculated from a heat balance on the combustion system, using parameters obtained in a field test. This ISO reference temperature will always be less than the true firing temperature as defined by GE, in many cases by 100 F/38 C or more for machines using air extracted from the compressor for internal cooling, which bypasses the combustor. *Figure 6* shows how these various temperatures are defined.

GE Gas Turbine Performance Characteristics

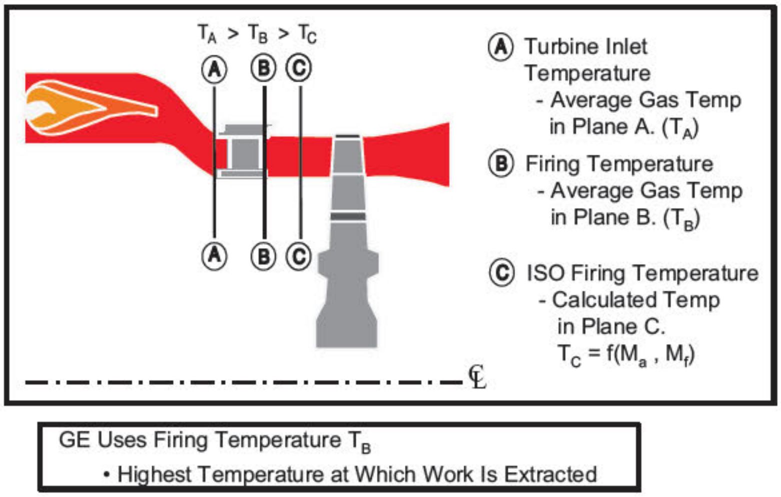


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Figure 6. Definition of firing temperature

Thermodynamic Analysis

Classical thermodynamics permit evaluation of the Brayton cycle using such parameters as pressure, temperature, specific heat, efficiency factors and the adiabatic compression exponent. If such an analysis is applied to the Brayton cycle, the results can be displayed as a plot of cycle efficiency vs. specific output of the cycle.

Figure 7 shows such a plot of output and efficiency for different firing temperatures and various pressure ratios. Output per pound of airflow is important since the higher this value, the smaller the gas turbine required for the same output power. Thermal efficiency is important because it directly affects the operating fuel costs.

Figure 7 illustrates a number of significant points. In simple-cycle applications (the top curve), pressure ratio increases translate into efficiency gains at a given firing temperature.

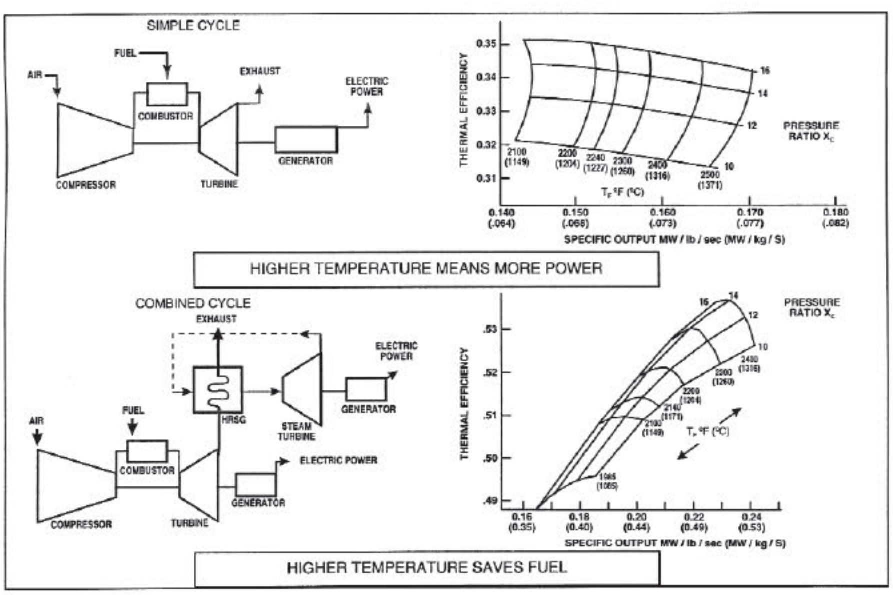

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Figure 7. Gas turbine thermodynamics

The pressure ratio resulting in maximum output and maximum efficiency change with firing temperature, and the higher the pressure ratio, the greater the benefits from increased firing temperature. Increases in firing temperature provide power increases at a given pressure ratio, although there is a sacrifice of efficiency due to the increase in cooling air losses required to maintain parts lives.

In combined-cycle applications (as shown in the bottom graph in *Figure 7*), pressure ratio increases have a less pronounced effect on efficiency. Note also that as pressure ratio increases, specific power decreases. Increases in firing temperature result in increased thermal efficiency. The significant differences in the slope of the two curves indicate that the optimum cycle parameters are not the same for simple and combined cycles.

Simple-cycle efficiency is achieved with high pressure ratios. Combined-cycle efficiency is obtained with more modest pressure ratios and greater firing temperatures. For example, the MS7001FA design parameters are 2420 F/1316 C firing temperature and 15.7:1 pressure ratio; while simple-cycle efficiency is not maximized, combined-cycle efficiency is at its peak. Combined cycle is the expected application for the MS7001FA.

Combined Cycle

A typical simple-cycle gas turbine will convert 30% to 40% of the fuel input into shaft output. All but 1% to 2% of the remainder is in the form of exhaust heat. The combined cycle is generally defined as one or more gas turbines with heat-recovery steam generators in the exhaust, producing steam for a steam turbine generator, heat-to-process, or a combination thereof.

Figure 8 shows a combined cycle in its simplest form. High utilization of the fuel input to the gas turbine can be achieved with some of the more complex heat-recovery cycles, involving multiple-pressure boilers, extraction or topping steam turbines, and avoidance of steam flow to a condenser to preserve the latent heat content. Attaining more than 80% utilization of the fuel input by a combination of electrical power generation and process heat is not unusual.

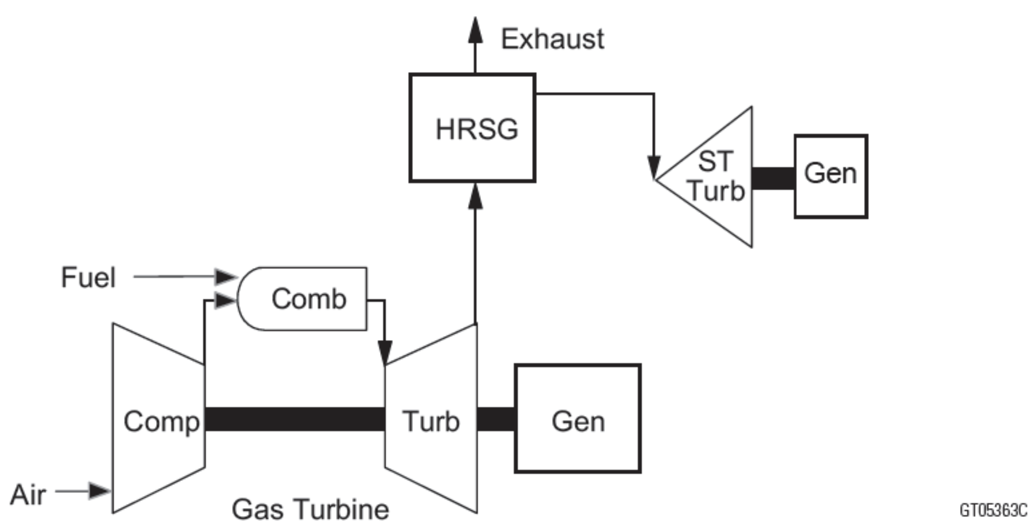

Figure 8. Combined cycle

Combined cycles producing only electrical power are in the 50% to 60% thermal efficiency range using the more advanced gas turbines.

Papers dealing with combined-cycle applications in the GE Reference Library include: GER-3574F, "GE Combined-Cycle Product Line and Performance"; GER-3767, "Single-Shaft Combined-Cycle Power Generation Systems"; and GER-3430F, "Cogeneration Application Considerations."

Factors Affecting Gas Turbine Performance

Air Temperature and Site Elevation

Since the gas turbine is an air-breathing engine, its performance is changed by anything that affects the density and/or mass flow of the air intake to the compressor. Ambient weather conditions are the most obvious changes from the reference conditions of 59 F/15 C and 14.7 psia/1.013 bar. *Figure 9* shows how ambient temperature affects the output, heat rate, heat consumption, and exhaust flow of a single-shaft MS7001. Each turbine model has its own temperature-effect curve, as it depends on the cycle parameters and component efficiencies as well as air mass flow.

Correction for altitude or barometric pressure is more straightforward. The air density reduces as the site elevation increases. While the resulting airflow and output decrease proportionately, the heat rate and other cycle parameters are not affected. A standard altitude correction curve is presented in *Figure 10.*

Humidity

Similarly, humid air, which is less dense than dry air, also affects output and heat rate, as shown in *Figure 11*. In the past, this effect was thought to be too small to be considered. However, with the increasing size of gas turbines and the utilization of humidity to bias water and steam injection for NO_x control, this effect has greater significance.

It should be noted that this humidity effect is a result of the control system approximation of firing temperature used on GE heavy-duty gas turbines. Single-shaft turbines that use turbine exhaust temperature biased by the compressor pressure ratio to the approximate firing temperature will reduce power as a result of

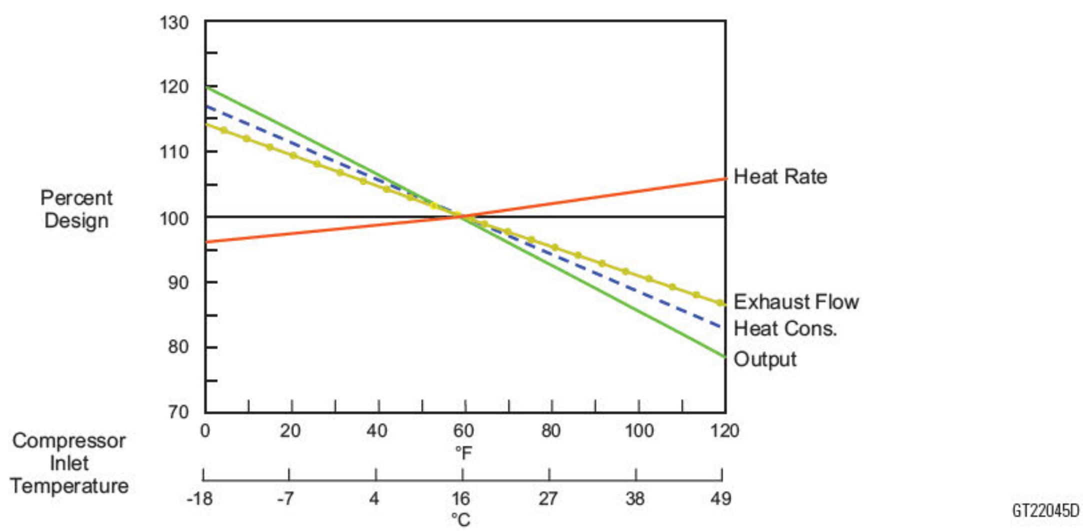

Figure 9. Effect of ambient temperature

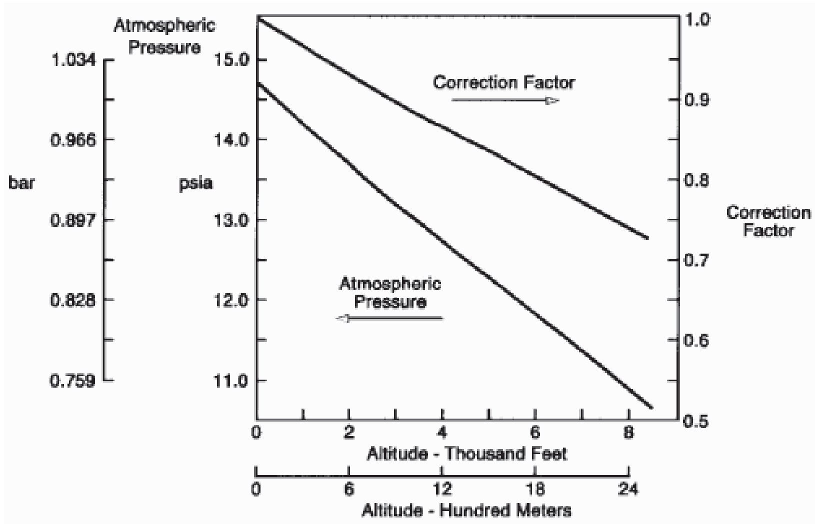

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Figure 10. Altitude correction curve

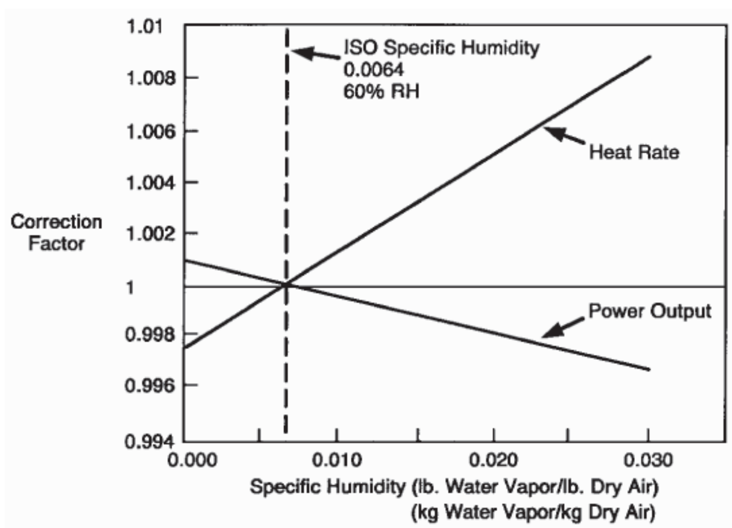

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Figure 11. Humidity effect curve

increased ambient humidity. This occurs because the density loss to the air from humidity is less than the density loss due to temperature. The control system is set to follow the inlet air temperature function.

By contrast, the control system on aeroderivatives uses unbiased gas generator discharge temperature to approximate firing temperature. The gas generator can operate at different speeds from the power turbine, and the power will actually increase as fuel is added to raise the moist air (due to humidity) to the allowable temperature. This fuel increase will increase the gas generator speed and compensate for the loss in air density.

Inlet and Exhaust Losses

Inserting air filtration, silencing, evaporative coolers or chillers into the inlet or heat recovery devices in the exhaust causes pressure losses in the system. The effects of these pressure losses are unique to each design. *Figure 12* shows

4 Inches (10 mbar) H_2O Inlet Drop Produces:

1.42% Power Output Loss
0.45% Heat Rate Increase
1.9 F (1.1 C) Exhaust Temperature Increase

4 Inches (10 mbar) H_2O Exhaust Drop Produces:

0.42% Power Output Loss
0.42% Heat Rate Increase
1.9 F (1.1 C) Exhaust Temperature Increase

GT18238C

Figure 12. Pressure drop effects (MS7001EA)

the effects on the MS7001EA, which are typical for the E technology family of scaled machines (MS6001B, 7001EA, 9001E).

Fuels

Work from a gas turbine can be defined as the product of mass flow, heat energy in the combusted gas (Cp), and temperature differential across the turbine. The mass flow in this equation is the sum of compressor airflow and fuel flow. The heat energy is a function of the elements in the fuel and the products of combustion.

Tables 1 and 2 show that natural gas (methane) produces nearly 2% more output than does distillate oil. This is due to the higher specific heat in the combustion products of natural gas, resulting from the higher water vapor content produced by the higher hydrogen/carbon ratio of methane. This effect is noted even though the mass flow (lb/h) of methane is lower than the mass flow of distillate fuel. Here the effects of specific heat were greater than and in opposition to the effects of mass flow.

Figure 13 shows the total effect of various fuels on turbine output. This curve uses methane as the base fuel.

Although there is no clear relationship between fuel lower heating value (LHV) and output, it is possible to make some general assumptions. If the fuel consists only of hydrocarbons with no inert gases and no oxygen atoms, output increases as LHV increases. Here the effects of Cp are greater than the effects of mass flow. Also, as the amount of inert gases is increased, the decrease in LHV will provide an increase in output. This is the major impact of IGCC type fuels that have large amounts of inert gas in the fuel. This mass flow addition, which is not compressed by the gas turbine's compressor, increases the turbine output. Compressor power is essentially unchanged. Several side effects must be considered when burning this kind of lower heating value fuels:

- Increased turbine mass flow drives up compressor pressure ratio, which eventually encroaches on the compressor surge limit
- The higher turbine power may exceed fault torque limits. In many cases, a larger generator and other accessory equipment may be needed
- High fuel volumes increase fuel piping and valve sizes (and costs). Low- or medium-Btu coal gases are frequently supplied at high temperatures, which further increases their volume flow

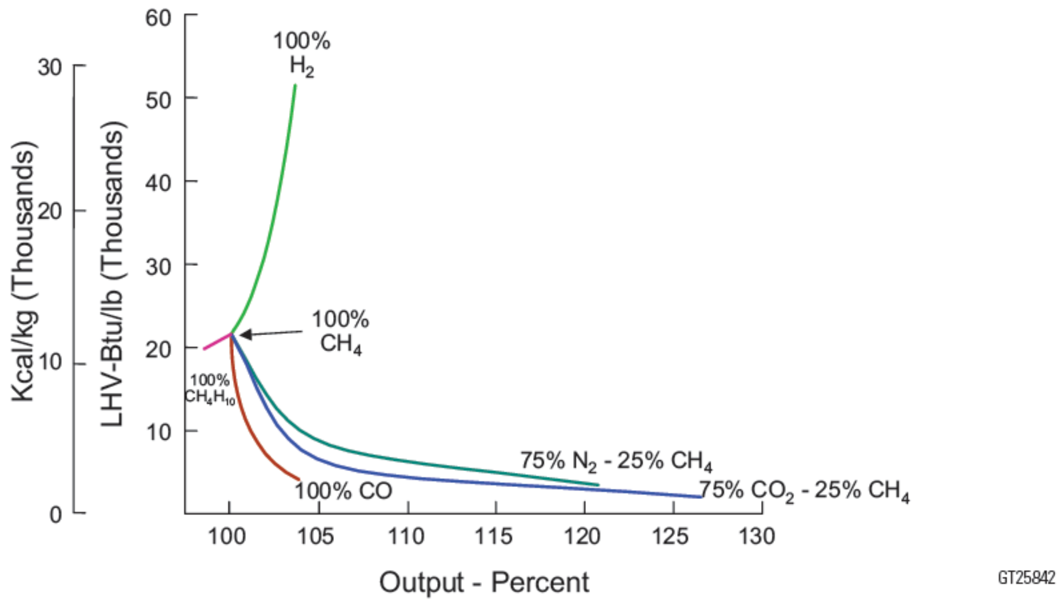

Figure 13. Effect of fuel heating value on output

- Lower-Btu gases are frequently saturated with water prior to delivery to the turbine. This increases the combustion products heat transfer coefficients and raises the metal temperatures in the turbine section which may require lower operating firing temperature to preserve parts lives
- As the Btu value drops, more air is required to burn the fuel. Machines with high firing temperatures may not be able to burn low Btu gases
- Most air-blown gasifiers use air supplied from the gas turbine compressor discharge
- The ability to extract air must be evaluated and factored into the overall heat and material balances

As a result of these influences, each turbine model will have some application guidelines on flows, temperatures and shaft output to preserve its design life. In most cases of operation with lower heating value fuels, it can be assumed that output and efficiency will be equal to or higher than that obtained on natural gas. In the case of higher heating value fuels, such as refinery gases, output and efficiency may be equal to or lower than that obtained on natural gas.

Fuel Heating

Most of the combined cycle turbine installations are designed for maximum efficiency. These plants often utilize integrated fuel gas heaters. Heated fuel results in higher turbine efficiency due to the reduced fuel flow required to raise the total gas temperature to firing temperature. Fuel heating will result in slightly lower gas turbine output because of the incremental volume flow decrease. The source of heat for the fuel typically is the IP feedwater. Since use of this energy in the gas turbine fuel heating system is thermodynamically advantageous, the combined cycle efficiency is improved by approximately 0.6%.

GE Gas Turbine Performance Characteristics

Diluent Injection

Since the early 1970s, GE has used water or steam injection for NO_X control to meet applicable state and federal regulations. This is accomplished by admitting water or steam in the cap area or "head-end" of the combustion liner. Each machine and combustor configuration has limits on water or steam injection levels to protect the combustion system and turbine section. Depending on the amount of water or steam injection needed to achieve the desired NO_X level, output will increase because of the additional mass flow. *Figure 14* shows the effect of steam injection on output and heat rate for an MS7001EA. These curves assume that steam is free to the gas turbine cycle, therefore heat rate improves. Since it takes more fuel to raise water to combustor conditions than steam, water injection does not provide an improvement in heat rate.

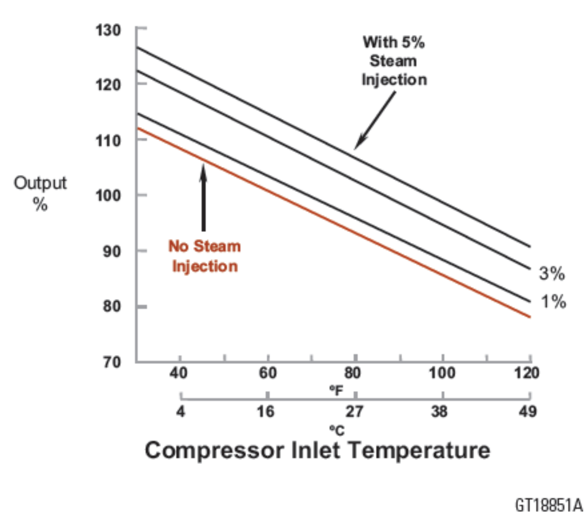

Figure 14. Effect of steam injection on output and heat rate

Air Extraction

In some gas turbine applications, it may be desirable to extract air from the compressor. Generally, up to 5% of the compressor airflow can be extracted from the compressor discharge casing without modification to casings or on-base piping. Pressure and air temperature will depend on the type of machine and site conditions. Air extraction between 6% and 20% may be possible, depending on the machine and combustor configuration, with some modifications to the casings, piping and controls. Such applications need to be reviewed on a case-by-case basis. Air extractions above 20% will require extensive modification to the turbine casing and unit configuration. *Figure 15* shows the effect of air extraction on output and heat rate. As a "rule of thumb," every 1% in air extraction results in a 2% loss in power.

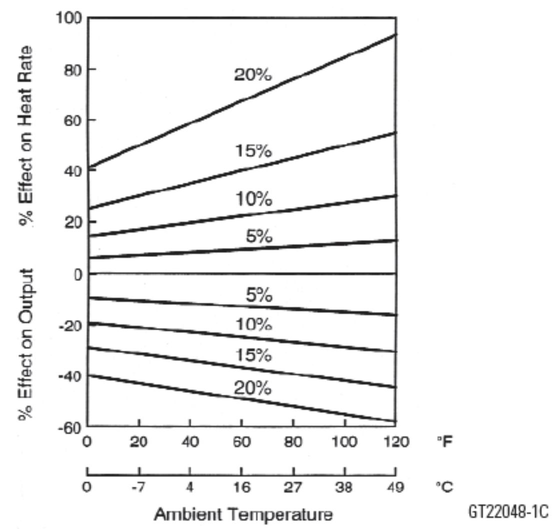

Figure 15. Effect of air extraction on output and heat rate

Performance Enhancements

Generally, controlling some of the factors that affect gas turbine performance is not possible. The planned site location and the plant configuration (such as simple- or combined-cycle) determine most of these factors. In the event additional output is needed, several possibilities to enhance performance may be considered.

Inlet Cooling

The ambient effect curve (see *Figure 9*) clearly shows that turbine output and heat rate are improved as compressor inlet temperature decreases. Lowering the compressor inlet temperature can be accomplished by installing an evaporative cooler or inlet chiller in the inlet ducting downstream of the inlet filters. Careful application of these systems is necessary, as condensation or carryover of water can exacerbate compressor fouling and degrade performance. These systems generally are followed by moisture separators or coalescing pads to reduce the possibility of moisture carryover.

As *Figure 16* shows, the biggest gains from evaporative cooling are realized in hot, low-humidity climates. It should be noted that evaporative cooling is limited to ambient temperatures of 59 F/15 C and above (compressor inlet temperature >45 F/7.2 C) because of the potential for icing the compressor. Information contained in *Figure 16* is based on an 85% effective evaporative cooler. Effectiveness is a measure of how close the cooler exit temperature approaches the ambient wet bulb temperature. For most applications, coolers having an effectiveness of 85% or 90% provide the most economic benefit.

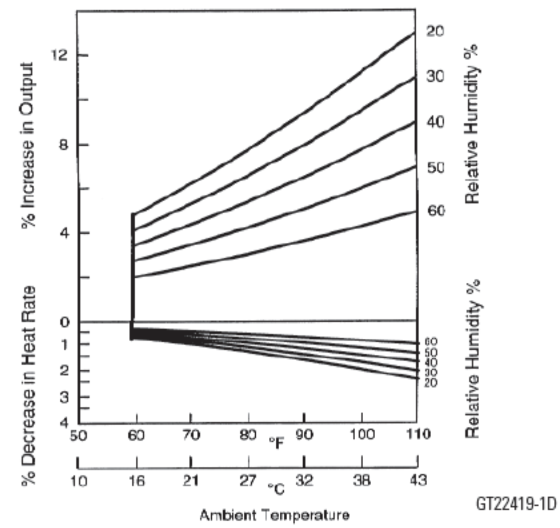

Figure 16. Effect of evaporative cooling on output and heat rate

Chillers, unlike evaporative coolers, are not limited by the ambient wet bulb temperature. The achievable temperature is limited only by the capacity of the chilling device to produce coolant and the ability of the coils to transfer heat. Cooling initially follows a line of constant

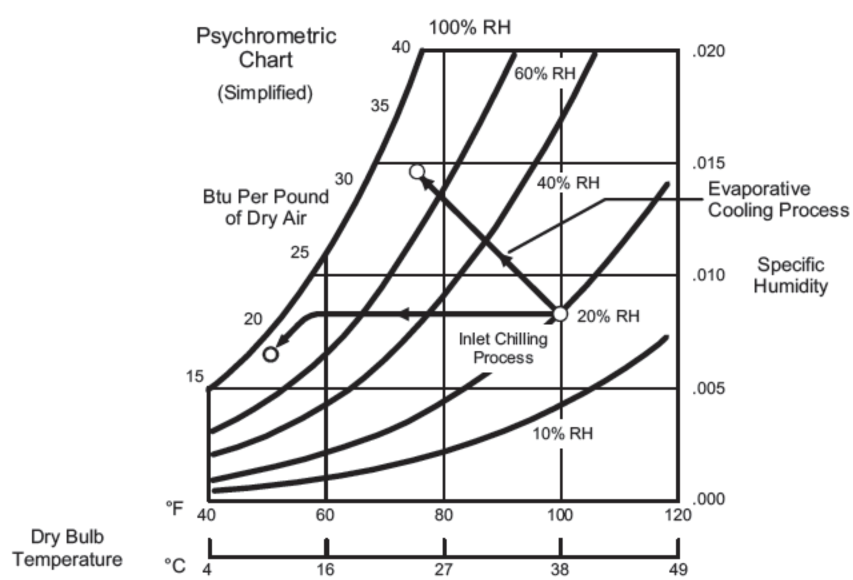

Figure 17. Inlet chilling process

specific humidity, as shown in *Figure 17*. As saturation is approached, water begins to condense from the air, and mist eliminators are used. Further heat transfer cools the condensate and air, and causes more condensation. Because of the relatively high heat of vaporization of water, most of the cooling energy in this regime goes to condensation and little to temperature reduction.

Steam and Water Injection for Power Augmentation

Injecting steam or water into the head end of the combustor for NO_X abatement increases mass flow and, therefore, output. Generally, the amount of water is limited to the amount required to meet the NO_X requirement in order to minimize operating cost and impact on inspection intervals.

Steam injection for power augmentation has been an available option on GE gas turbines for over 30 years. When steam is injected for power augmentation, it can be introduced into the compressor discharge casing of the gas turbine as well as the combustor. The effect on output and heat rate is the same as that shown in *Figure 14*. GE gas turbines are designed to allow up to 5% of the compressor airflow for steam injection to the combustor and compressor discharge. Steam must contain 50 F/28 C superheat and be at pressures comparable to fuel gas pressures.

When either steam or water is used for power augmentation, the control system is normally designed to allow only the amount needed for NO_X abatement until the machine reaches base (full) load. At that point, additional steam or water can be admitted via the governor control.

Peak Rating

The performance values listed in *Table 1* are base load ratings. ANSI B133.6 Ratings and Performance defines base load as operation at 8,000 hours per year with 800 hours per start. It also defines peak load as operation at 1250 hours per year with five hours per start.

In recognition of shorter operating hours, it is possible to increase firing temperature to generate more output. The penalty for this type of operation is shorter inspection intervals. Despite this, running an MS5001, MS6001 or MS7001 at peak may be a cost-effective way to obtain more kilowatts without the need for additional peripheral equipment.

Generators used with gas turbines likewise have peak ratings that are obtained by operating at higher power factors or temperature rises. Peak cycle ratings are ratings that are customized to the mission of the turbine considering both starts and hours of operation. Firing temperatures between base and peak can be selected to maximize the power capabilities of the turbine while staying within the starts limit envelope of the turbine hot section repair interval. For instance, the 7EA can operate for 24,000 hours on gas fuel at base load, as defined. The starts limit to hot section repair interval is 800 starts.

For peaking cycle of five hours per start, the hot section repair interval would occur at 4,000 hours, which corresponds to operation at peak firing temperatures. Turbine missions between five hours per start and 800 hours per start may allow firing temperatures to increase above base but below peak without sacrificing hours to hot section repair. Water injection for power augmentation may be factored into the peak cycle rating to further maximize output.

Performance Degradation

All turbomachinery experiences losses in performance with time. Gas turbine performance degradation can be classified as recoverable or non-recoverable loss. Recoverable loss is usually associated with compressor fouling and can be partially rectified by water washing or, more thoroughly, by mechanically cleaning the compressor blades and vanes after opening the unit. Non-recoverable loss is due primarily to increased turbine and compressor clearances and changes in surface finish and airfoil contour. Because this loss is caused by reduction in component efficiencies, it cannot be recovered by operational procedures, external maintenance or compressor cleaning, but only through replacement of affected parts at recommended inspection intervals.

Quantifying performance degradation is difficult because consistent, valid field data is hard to obtain. Correlation between various sites is impacted by variables such as mode of operation, contaminants in the air, humidity, fuel and dilutent injection levels for NO_X. Another problem is that test instruments and procedures vary widely, often with large tolerances.

Typically, performance degradation during the first 24,000 hours of operation (the normally recommended interval for a hot gas path inspection) is 2% to 6% from the performance test measurements when corrected to guaranteed conditions. This assumes degraded parts are not replaced. If replaced, the expected performance degradation is 1% to 1.5%. Recent field experience indicates that frequent off-line water washing is not only effective in reducing recoverable loss, but also reduces the rate of non-recoverable loss.

One generalization that can be made from the data is that machines located in dry, hot climates typically degrade less than those in humid climates.

Verifying Gas Turbine Performance

Once the gas turbine is installed, a performance test is usually conducted to determine power plant performance. Power, fuel, heat consumption and sufficient supporting data should be recorded to enable as-tested performance to be corrected to the condition of the guarantee. Preferably, this test should be done as soon as practical, with the unit in new and clean condition. In general, a machine is considered to be in new and clean condition if it has less than 200 fired hours of operation.

Testing procedures and calculation methods are patterned after those described in the ASME Performance Test Code PTC-22-1997, “Gas Turbine Power Plants.” Prior to testing, all station instruments used for primary data collection must be inspected and calibrated. The test should consist of sufficient test points to ensure validity of the test set-up. Each test point should consist of a minimum of four complete sets of readings taken over a 30-minute time period when operating at base load. Per ASME PTC-22-1997, the methodology of correcting test results to guarantee conditions and measurement uncertainties (approximately 1% on output and heat rate when testing on gas fuel) shall be agreed upon by the parties prior to the test.

Summary

This paper reviewed the thermodynamic principles of both one- and two-shaft gas turbines and discussed cycle characteristics of the several models of gas turbines offered by GE. Ratings of the product line were presented, and factors affecting performance were discussed along with methods to enhance gas turbine output.

GE heavy-duty gas turbines serving industrial, utility and cogeneration users have a proven history of sustained performance and reliability. GE is committed to providing its customers with the latest in equipment designs and advancements to meet power needs at high thermal efficiency.

GE Gas Turbine Performance Characteristics

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Performance Characteristics of an Air-Cooled Condenser Under Ambient Conditions

A. Rupeshkumar V.Ramani, B. Amitesh Paul, D. Anjana D. Saparia

Abstract -- **In this paper effects off air flow pattern as well as ambient conditions are studied. Unfortunately ACC becomes less effective under high ambient temperature and windy conditions. Fin cleaning plays a vital role in heat rejection. External surface cleaning improves air side heat transfer coefficient. Ambient conditions affect the steam temperature and heat rejection rate. It is observed that rise in wind velocity decreases thermal effectiveness of ACC up to considerable level. Ambient temperature not only affects performance of ACC at the same time turbine back pressure also increases with rise in ambient temperature. Skirts are effective solution to reduce the effect of wind on volumetric effectiveness. Hot air recirculation increases with wind velocity. Now a days wind walls are used to reduce this effect. Second option is to increase fan speed. It counter affects on electrical power consumption.**
Index Terms -- **Ambient temperature, Hot air Recirculation, Thermal effectiveness**

I. INTRODUCTION

Due to the decreasing availability and rising cost of cooling water, dry-cooling towers or direct air-cooled condensers (ACC's) are increasingly employed to reject heat to the environment in modern power plants incorporating steam turbines. Unfortunately, with an increase in the ambient temperature, the effectiveness of these cooling systems decreases resulting in a corresponding reduction in turbine efficiency. The reduction in turbine output during hot periods may result in a significant loss in income, especially in areas where the demand and cost for power during these periods is high.

II. DRY COOLING

As the availability of water required for wet-cooling systems becomes more limited, modern power plants are increasingly employing indirect dry-cooling towers or direct air-cooled steam condensers to condense steam turbine exhaust vapor. Direct air-cooled condenser units in power plants usually consist of finned tubes arranged in the form of a delta or A-frame to drain condensate effectively, reduce distribution steam duct lengths and minimize the required ground surface area.

A-frame direct air-cooled steam condenser units are normally arranged in multi-row or multistreet arrays. Each street consists of three to five main condenser units with a dephlegmator or secondary reflux condenser connected in series. The addition of the dephlegmator increases the steam flow in the main condenser units to such an extent that there is a net flow of steam out of every tube. This inhibits the accumulation of non4 condensable gases in the tubes that may lead to corrosion, freezing or a reduction in the heat transfer capability of the system.

Unlike the thermal performance of wet-cooling systems, which are dependent on the wet bulb temperature of the ambient air, an air-cooled system's performance is directly related to the dry bulb temperature. The ambient dry bulb temperature is normally higher than the wet bulb temperature and experiences more drastic daily and seasonal changes. Although air-cooled systems provide a saving in cooling water, they experience performance penalties during periods of high ambient temperatures.

III. CURRENT WORLD WIDE ACC SCENARIO

Selection of cooling technology for use in power plants is an economic decision which is frequently influenced by local environmental and political factors. In the early days, use of dry cooling methods was sometimes the only feasible option due to scarcity of water at otherwise attractive plant sites in arid and semi-arid regions of the world. However, the combined trends of increasing demands for power, more widespread scarcity of available water for cooling and increasing costs of water and tighter environmental restraints related to use of wet cooling systems served to broaden selection of the ACC option, in term of both number and size of units.

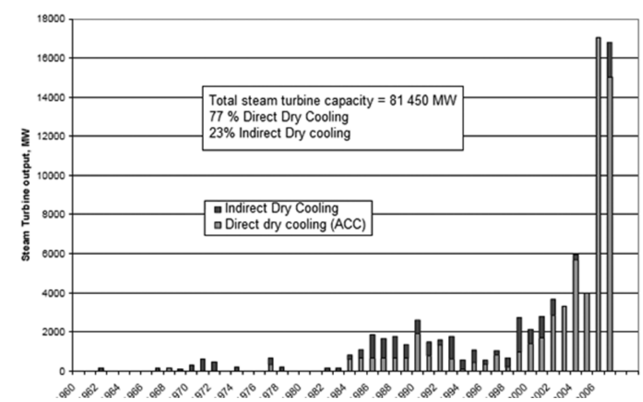

Fig.1 Worldwide installation of dry cooled power plants.

Graph given above depicts the trends in installation of ACCs and indirect dry cooling systems on units >100MW since 1960. (Indirect designs employ water cooling of turbine condensate in a closed system arrangement with air-cooled exchangers used to reject the heat transferred to the cooling water during condensation.) From this figure it quickly becomes apparent that increased interest started around the mid 1980s has generally continued to grow, particularly over the last 10 years.

IV. The Impact of Air Cooled Condenser on Plant Design and Operations.

Air-cooled condensers were first introduced into the U.S. power industry in the early 1970's, but only during the last decade has the number of installations greatly increased, largely in response to the growing attention being paid to environmental concerns. The rising importance of this rather different technology for the condensing and recovery of exhaust steam calls for a broader understanding of the associated design and application principles involved, as well as of the performance monitoring techniques and cleaning methods that have to be applied.

Over the past 30 years there has been a growing and competing demand for water for both domestic and industrial use and this has brought an increased interest in the use of air as a cooling medium in place of water. In the utility industry, the earliest applications for the air-cooled condensing of exhaust steam were modified air-cooled heat exchangers similar to those already in use by the process industries. Eventually, air-cooled condensers designed for the utility industry evolved into a configuration that recognized the special needs of condensing a large volume of low pressure vapor as well as the removal of non-condensable.

V. The Environmental Protection Agency and Dry Cooling

In 2000, the U.S. Environmental Protection Agency conducted a comparative study of the environmental impacts of wet vs. dry cooling. Their conclusion was that the energy consumption per lb. condensate was higher for dry cooling than for wet cooling and that the atmospheric emissions associated with that energy consumption was also higher. These disadvantages are offset by the cooling water intake flow being reduced by 99% over that required by a once-through system; or 4-7% over a closed cooling water system. They also noted that dry cooling eliminates visual plumes, fog, mineral drift and water treatment and waste disposal issues. However, their conclusion was that, 'dry cooling does not represent the "Best Technology Available (BTA) for minimizing environmental impact".

Much of the E.P.A's concern is that 'the high costs and energy penalty of dry cooling systems may remove the incentive for replacing older coal-fired plants with more efficient and environmentally favorable new combined-cycle facilities', the latter presumably equipped with wet-cooling systems.

VI Corrosion problems with Air Cooled Condensers.

Corrosion of the carbon steel components in these large systems has been a concern because of the impact of high iron levels and air in-leakage. The maximum corrosion has been observed at the entries to the A-frame ACC tubes. The mechanism of this corrosion is not fully understood and little work has been expended in trying to rectify this. Based on various analyses the actual corrosion appears to be a flow-accelerated corrosion (FAC) derivative where local indigenous magnetite is removed from the surface of the ACC tube leaving a very intergranular surface appearance. Adjacent to these areas where the local turbulence of the two-phase media is not as great, the magnetite deposits on the surface. There are clear boundaries between the regions where corrosion/ FAC takes place (white bare metal) and regions where deposition (black areas) occurs.

Fig. 2 DHACI Indices 1-5 for upper ducts and tube entries.

ACC Corrosion Index:

After inspecting a number of ACCs around the world, two of the authors developed an index for quantitatively defining the internal corrosion status of an ACC. This is known by the acronym DHACI (Dooley Howell ACC Corrosion Index). The index separately describes the lower and upper sections of the ACC, according to the following

Upper Section

Upper duct/header, ACC A-frame tube entries. Index: 1, 2, 3, 4 or 5.

1. Tube entries in relatively good shape; possibly some areas with dark deposits in first few inches of tube interior. No corrosion or FAC.
2. Various black/grey deposits on tube entries as well as flash rust areas, but no white bare metal areas. Minimal corrosion/FAC.
3. Few white bare metal areas on a number of tube entries. Some black areas of deposit mild corrosion/FAC.
4. Serious white (bare metal) areas on/at numerous tube entries. Extensive areas of black deposition adjacent to white areas within tubes. Serious corrosion/FAC.
5. Most serious. Holes in the tubing or welding. Obvious corrosion on many tube entries.

VII. Cleaning Techniques for Air-Cooled Condensers

The three principal methods for cleaning the external surfaces of air-cooled condensers are as follows:

- Fire hose
- High pressure Handlance
- Semi-Automated cleaning machine

1) Fire Hose

While the volume of water consumed is high, a fire hose offers only a low washing effect because of the low pressure involved. The galvanized surfaces of the tubes and fins are not damaged by this method. Unfortunately, in order to perform cleaning the plant must be taken out of service and scaffolding erected. The process may also be time and labor intensive depending on unit design and accessibility. It has also been found that use of the fire hose only leads to small performance improvements even if the surfaces seem to be optically clean.

2) High Pressure Handlance

The high pressure handlance method offers low water consumption and a high water pressure. Unfortunately, the latter can cause the galvanized surfaces to become damaged or even cause the fins to be snapped off. Again, the plant must be taken out of service and scaffolding erected in order that cleaning can be performed. Unit accessibility will affect cleaning productivity. As with the use of a fire hose, this procedure only leads to small performance improvements and, once the fouling material has been compressed, it hinders heat transfer and obstructs air flow.

3) Semi-Automated Cleaning Machine

The semi-automated cleaning machine, an example of which is shown in Figure, uses a significant volume of water; but at a pressure that, while allowing for effective surface cleaning, avoids damaging galvanized surfaces and fins.

Fig. 3 Semi-Automated pressure cleaning.

The main components of the system include a nozzle beam, a tracking system. The nozzle beam matches to the tube bundle geometry, with a constant jet angle. Optimizing the geometry of the nozzle beam involves determining the proper nozzle distance to the surface.

VIII. UltraTech Air-Cooled Condenser details

ACC transfers exhaust steam into condensate, then gives condensate to water circulation. Exhaust steam comes from turbine gets into ACC steam collection header through steam pipe. In the steam collection header, steam falls down in fin tubes in "A"frame of air cooled condenser due to vacuum.

TABLE I
ULTRATECH AIR COOLED CONDENSER SPECIFICATION

Air Cooled Condenser		
1.	Manufacturer	Wuxi Dongsheng
2.	Manufacturer address	Shandong Jinan Power Equipment Factory, Jinan 250100, China
3.	No of Condenser	4 Nos
4.	Fan Type	Forced type
5.	No of fan	6 Nos.
6.	Fan dia Ø (Mtr)	9. 8
7.	Blade material	FRP
8.	Hub Material	C40 - hot dip galvanized
9.	Size of Exhaust steam duct (mm)	1800
10.	Size of branch pipe going from main pipe to each stack of 3 fans	1600
11.	Total weight Air condenser cooling (T /Unit)	600
12.	Flow finned tubes	XT10x3-2-247-0.3Q-12.8/TC-2
13.	Counter flow finned tubes	XT9.4x3-2-232-0.3Q-12.8/TC-2
14.	A Frame	GXT22X36-97.25/7
15.	Forced draft fan system	G-TF97.25B5-C91
16.	Block wind wall	D9726
17.	Motor KW / Voltage	90 / 416

The steam in tubes is condensate by air come from fan. The condensate will be collected in the steam collection header and gets the bottom of "A" structure; then goes to CRT (hot well).

Fig. 4 Air Cooled condenser components (Ultratech Power plant)

TABLE II
THERMAL AND HYDRAULIC SPECIFICATIONS

No.	Description	Unit	Specification
1	Type	-----	N-2 , S-2
2	Mode	-----	Air cooling
3	Course media		Exhaust steam
4	Heat exchange value	Kcal /h	36970000
5	Actual heat transfer area	M²	140200
6	Weight	T	56.4
7	Length	mm	9400
8	Tube	bar	115
9	Quantity per row	bar	57 or 58
9	tube designed pressure	MPa	0.294
10	Tube designed temperature	℃	120
11	Air flow	m/s	2.7
12	Diameter of fin	mm	119/49/0.35
13	Distance of fins	mm	3.6
14	Total air quality flow	Kg/h	14210000
15	Total air volume flow	cu. m/sec	3500
16	Air inlet flow velocity	m/s	43.5
17	Quantity of constant speed fans	Set	6
18	Quantity of regulated speed fan	Set	1
19	Material	Hot galvanized carbon steel	
20	Tube	Elliptical	
21	Fouling factor	Steam side:0.0001/air side:0.0002	
22	Tube arrangement	Straight flow and counter flow	
23	Mode of fins	Hot galvanized	
24	Material	Carbon steel	
25	Manufacturer	Shanghai Turbine Co. Ltd.	

We use two condensate pumps. They pump condensate water to condensate water header, gland seal cooler and LPH, at last, gets to deaerator. The un-condensate is exhausted by steam ejector. For any condenser condensation of steam as well as removal of dissolved gases are important. Each condenser contains six fans. Fan no. 1, 3, 4 & 6 are for the condensation of turbine outlet steam. Fan no. 2 & 5 are for dephlegmator section. Dephlegmator section is connected with steam ejector system. For this particular plant being at sea shore ambient temperature playing effective roll.

Due to sea shore it is not going as higher as compared to interior regions. As shown in the sketch dephlegmator section is just like sandwich form. A-Frame air cooled condenser is shown in the sketch.

IX. Results and Discussion

1) Effect of Wind Velocity on Hot Air Recirculation

From the above results, it is found that the HAR of the ACC system is extremely serious when the wind blows normal to the boiler house.

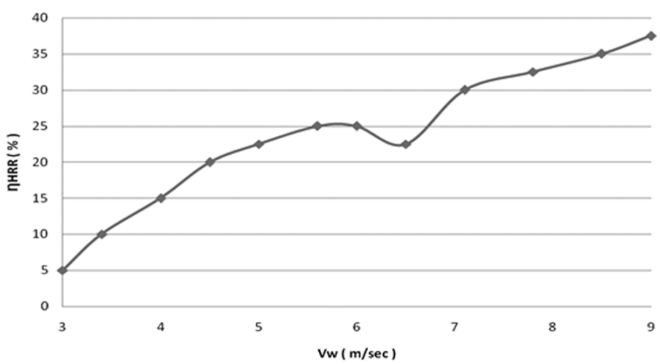

Fig. 5 Heat Recirculation at different Wind velocities.

In order to the further understand the impact of the unfavorable wind condition on the HAR, twelve wind speeds are selected for the numerical calculation. The curve shows that the HRR varies with the wind speeds. It is clearly seen that HRR maintains the growing trend with the increase of wind speed. With the increase of the wind speed, the interaction and disturbance between hot exhausted air and weak flow of leeward side of the boiler house and turbine room are gradually enhanced, and in the addition of intensive suction of axial flow fans, a lot of hot exhausted air involves into the fan-inlet of the edge of the ACC platform. However, when the wind speed reaches up to very high level reduction is possible of the HAR of the ACC system. The main reason that causes this reduction trend is that under the strong wind conditions, the forced convection action of oncoming wind and hot exhausted air are evidently reinforced, therefore most of the heat quantity are transferred and diffused to the downwind of the ACC platform.

2) Hot air recirculation at different fan speeds:

The ambient wind field around the ACC system is one of major factors that cause the HAR, and the variation of fan rotational speed will inevitably lead to the changes of wind fields, so the fan rotational speed is also an indirect factor affecting the HAR. In the current calculations, four rotational speeds of 800 to 1400 r/min are considered for the comparison and analysis.

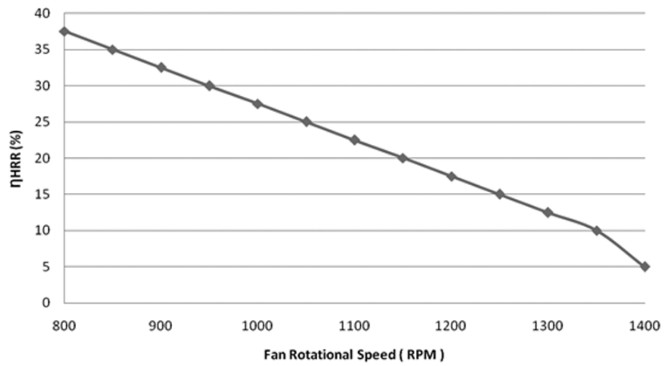

Fig. 6 Heat Recirculation as a function of Fan speed.

According to the relation that the volume flow rate is proportional to the rotational speed, in the ACC cells around the edge of ACC platform shown in the graph. The temperature of the fans boundary and the ambient temperature are both 30˚C. The ambient wind speed is in between 6 to 9 m/s. The graph shows that how the HRR varies with the increases of rotational speed. It is concluded that the HRR gradually reduce with the acceleration of rotational speed. The reasonable explanations causing this phenomenon are that accelerating the rotational speed of the edge fans leads to the increment of fan flow rate, which makes inlet and outlet wind speed of the ACC both increase correspondingly, thus aggravating the convective heat exchange between the cooling air and the finned tubes. The temperature of the hot air exhausted from the ACC has aggrandized, but the kinetic energy along the vertical direction will increase, which can weaken the entrainment phenomena of flow-field around the ACC on the hot exhaust air. Finally, the hot air involved into fan-inlet is to reduce and its temperature is to lower.

3) Effect of wind velocity on effectiveness:

As the wind speed increases inlet flow distortion experienced. The thermal effectiveness decreases as the wind velocity increases as shown in the graph. The flow distortion and regarding low pressure region at the upstream region of the fan contributes in the decrease of ACC performance. The wind itself has positive impact on certain fans also.

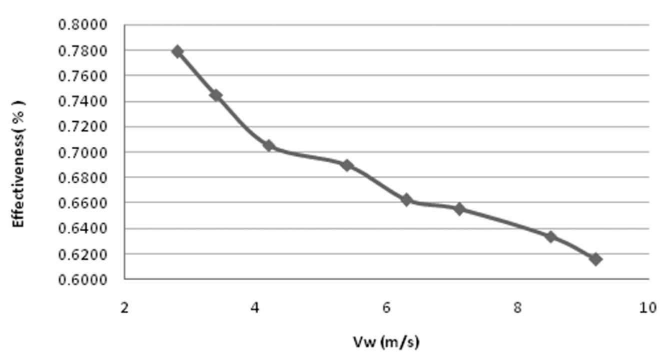

Fig. 7 Effectiveness at different Wind velocities.

The volumetric effectiveness also can be increased. Relatively at low wind speeds effectiveness is higher. As the wind velocity increases due to flow distortion and low pressure regions thermal effectiveness of ACC is reducing up to level of 61.5%. The favorable thing for ACC is that wind velocity improves volumetric effectiveness.

4) Ambient Temperature effect on heat rejection:

The magnitude of the vortex increases in the downstream direction due to increased air temperature. ACC becomes less effective when ambient temperature is higher.

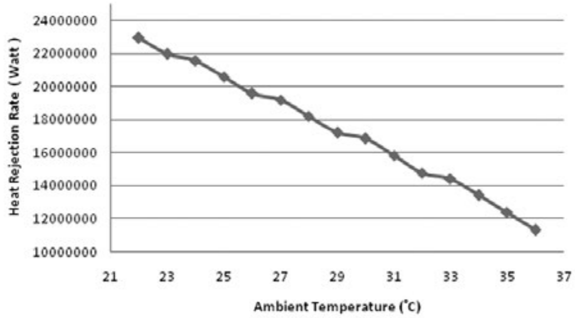

Fig. 8 Heat Rejection for various Ambient temperatures

As ambient temperature increases from 22˚C heat rejection rate decreases as its effect on LMTD. Up to large extent heat rejection rate depends on inlet (ambient) temperature and ambient temperature depends on the seasons. Normally in winter heat rejection rate is as per design. In summer as the ambient temperature increases it adversely affect on heat rejection because it decreases LMTD and ultimately heat rejection. Due to this reason in some of the areas of the world they are using water spray techniques to maintain heat rejection rate constant. Ultra tech power plant is situated at sea shore and where ambient temperature never exceeds 36˚C. In countries like India ACC can work better nearer to sea shore.

5) Cleaning of an ACC.

Heat is rejected in the atmosphere and rejection rate is largely dependent on the surface condition of fins. Due to different weather conditions fouling occurs on the surface of exposed surfaces. Due to the deposition it decreases heat rejection rate and ultimately cleaning becomes inevitable. Thermal effectiveness increases even though mass flow rate of air decreases. By cleaning coefficient of heat transfer (air side) is increasing. For different values of coefficient calculations are made and plotted graph clearly indicates that as cleaning progresses less mass flow rate of air is required.

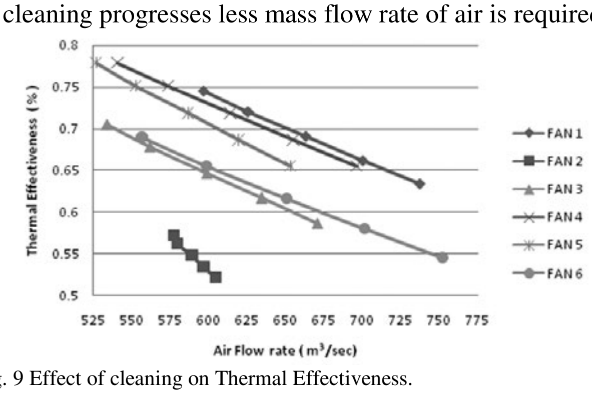

Fig. 9 Effect of cleaning on Thermal Effectiveness.

At the same time thermal effectiveness also increases. For different 5 values of heat transfer coefficients calculations have been made. As the cleaning progresses required mass flow rate decreases for the same heat rejection. Cleaning not only reduces mass flow rate of air but gives considerable savings in terms of rupees.

6) Ambient Temperature impact on Turbine Back Pressure:

Ambient temperature plays key role not only heat rejection but it also effects on turbine back pressure. As the turbine back pressure increases output of turbine decreases. Increased back pressure will reduce heat transfer rate and adversely affect on vacuum to be maintained. Increased ambient temperature reduces heat transfer rate due to that steam to condensation conversion rate is badly affected.

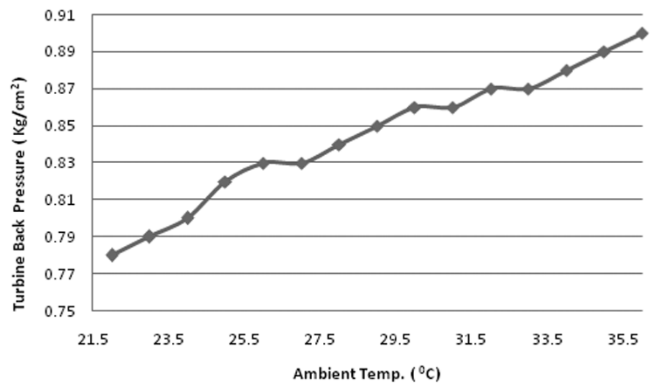

Fig. 10 Turbine Back pressure Vs. Ambient temperature.

This is the reason why turbine back pressure is increasing. In summer turbine back pressure rising occurs because of higher ambient temperature. As the ambient temperature increase turbine back pressure starts to increases. It increases from 0.78 to 0.9 Kg/cm^2 for the rise in temperature difference of only 14˚C.

7) Skirt effect on volumetric performance of ACC:

The addition of skirt does increase the performance of an ACC measurably under windy conditions, by modifying the flow into the ACC and by reducing the hot air recirculation that exists at the downstream edge fans. The low pressure region at the inlet of the upstream edge fans is displaced away from the fan inlet, resulting in an increase in the volumetric effectiveness of the upstream edge fans and a corresponding increase in the volumetric effectiveness of the ACSC.

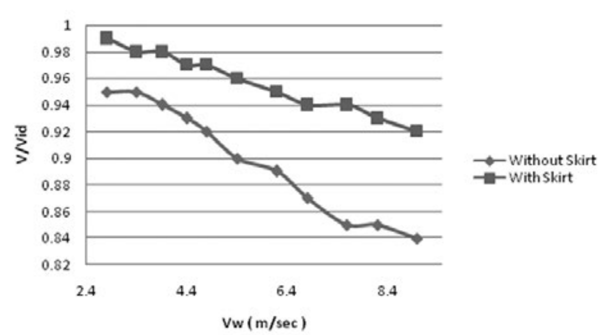

Fig. 11 Effect of Skirt on Volumetric Effectiveness.

At a relatively low wind speed (3 m/s) the volumetric effectiveness of the ACSC with a 3 m skirt is approximately 99%. Even though the volumetric flow rates of the upstream edge fans are below the ideal volumetric flow rate, the volumetric effectiveness of the downstream fans are increased to the windy conditions.

X. CONCLUSION

The primary focus of this study was to determine performance trends of an ACC under atmospheric parameters.

- Ambient temperature plays key role in the performance of ACC. Generally ACC is advisable where ambient temperature not rising much, especially at sea shore areas. More than that ambient temperature also effects on turbine back pressure which can reduce output power. In both these cases ambient temperature impact is considerable.
- After ambient temperature wind velocity is the secondary parameter which affects on ACC performance. As the wind velocity increases effectiveness (thermal and volumetric) decreases and hot air recirculation increases.
- Hot air recirculation is generally observed in so many plants. To minimize fan rotational speed to be increased. This is not the solution because electrical energy consumption by fan will increase. The optimum solution is wind wall on the sides of the radiator.
- Various techniques for cleaning are adopted to increase heat transfer rate. As the cleaning progresses for various heat transfer coefficients (air side) improves. Ultimately which accelerates heat rejection rate to atmosphere.

XI. REFERENCES

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[6] Operation Manual (Steam Turbine Section) for 4X23M Thermal Power Plant at Gujarat Cement Works, Document NO.: CMEC-GCW-OM-001

[7] Thermal Power Plant Diary with Specifications, for 4X23M Thermal Power Plant at Gujarat Cement Works, Rajula.

REDACTED
Docket No. UE 400
Exhibit PAC/700
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Daniel J. MacNeil

June 2022

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ATTACHED EXHIBITS

Exhibit PAC/701 – PacifiCorp Response to Staff Data Request OPUC 74

Q. Are you the same Daniel J. MacNeil who submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my reply testimony is to respond to the rebuttal testimony of the Public Utility Commission of Oregon (Commission) Staff (Staff) witness Brian Fjeldheim and Sierra Club witness Ed Burgess as it relates to the Company's modeling of net power costs for the 2022 Transition Adjustment Mechanism (TAM).

Q. Please summarize your testimony.

A. My testimony first provides clarification requested by Staff related to loss of load hour (LOLH) reliability metrics, detailing the different conditions that could lead to a loss of load event and how PacifiCorp allows for a small probability of loss of load events in its planning processes. My testimony next addresses Sierra Club's interpretations of the Jim Bridger coal supply analysis conducted in the 2021 Integrated Resource Plan (IRP) and the associated IRP acknowledgement proceeding, docket LC 77, as well as that contained in the recently filed Jim Bridger Long-Term Fuel Supply Plan (LTFP). Finally, I respond to concerns raised by Sierra Club related to the coal demand scenarios used to evaluate the Naughton Coal Supply Agreement (CSA) and related to the Company's ongoing modeling of the terms of the Huntington CSA.

II. REPLY TESTIMONY

A. Regulation Reserve Requirements

Q. Have parties identified concerns related to the reliability metrics discussed in your direct testimony?

A. Yes. Staff states that "the Company used several differing values for the LOLH reliability metric (2.4, 1.06, and 0.50 hours)" and indicated that Staff data request 74 was intended to clarify why these values were referenced.[1]

Q. Did the Company respond to Staff data request 74?

A. Yes. The Company provided a response on May 11, 2022, a copy of which is attached to my testimony as Exhibit PAC 701.

Q. What does the 2.4 hours per year LOLH metric represent?

A. This is PacifiCorp's interpretation of the one-day-in-10-years reliability standard that is commonly used for electric utility resource planning purposes. This standard means that, while a utility would use all available options to avoid loss of load occurring in actual operations, resource planning is not intended to eliminate all possible loss of load risk. The difference being that doing something very expensive for an hour or two is a lot less expensive than procuring a resource that may only be needed once in a 10-year period. At some point avoiding the risk of loss of load is not worth the cost.

With that in mind, PacifiCorp's recent IRPs have identified 2.4 hours per year (24 hours over 10 years) as the maximum acceptable loss of load risk for use in modeling and portfolio development. This is a relatively lenient interpretation of the

[1] Staff/500 Fjeldheim/13-14.

one-day-in-10-years standard, as it allows for more frequent events spread across multiple days, so long as the total number of hours is sufficiently low. A more restrictive view, based on the number of events, could require shortfalls to occur on no more than one day in a ten-year period.

Q. What does the 1.06 hours per year LOLH metric represent?

A. This is an estimate calculated in the 2019 IRP of the loss of load risk PacifiCorp's customers face associated with the uncertainty in load, hydro generation, and thermal unit outages, calculated based on PacifiCorp's system. In this analysis, various combinations of hotter than normal summer conditions (or sometimes colder winter conditions), a dry water year, and simultaneous thermal unit outages resulted in periods where the modeled portfolio was unable to serve all load. The planning reserve margin study conducted for PacifiCorp's 2019 IRP evaluated this loss of load risk associated with these input variables as incremental resources were added to PacifiCorp's portfolio.[2] It ultimately identified a 13 percent target planning reserve margin for use in portfolio development, i.e., that resources should be added with effective capacity equal to 113 percent of coincident peak load. A portfolio with a 13 percent planning reserve margin resulted in an average of 1.06 loss of load hours per year and 0.46 loss of load events per year, as detailed in Table I.4 in the planning reserve margin study.[3] While this is less than 2.4 hours per year, a lower planning reserve margin would have difficulty meeting contingency reserve requirements (approximately 6 percent of hourly load) and an outage at single large thermal unit (a

[2] PacifiCorp 2019 Integrated Resource Plan Report, Vol. II at 137; available at: https://www.pacificorp.com/energy/integrated-resource-plan.html.
[3] Id., Vol. II, Appendix I – Planning Reserve Margin Study at 143.

number of PacifiCorp's units represent 4-6 percent of peak load), leaving little ability to cover multiple outages, higher load, or lower hydro.

Q. What does the 0.50 hours per year LOLH metric represent?

A. The 0.50 hours per year is the incremental loss of load risk that will not be covered by the regulation reserve forecast methodology developed in the 2021 IRP, as described in my direct testimony and employed in this proceeding. If PacifiCorp only maintained a supply of regulation reserves that was equal to the hourly regulation reserve forecast, 0.50 hours per year of shortfalls would be expected to occur. While Energy Imbalance Market (EIM) imports could reduce the risk that load was actually curtailed, PacifiCorp's allocated share of the EIM diversity benefits is already accounted for in the forecasted hourly requirement, and incremental imports necessitated by insufficient resources, rather than economics, could be considered leaning on other EIM participants. A tenet of the EIM is that each participating entity remains individually responsible for its reliability obligations, so leaning would be inappropriate.

The loss of load risk due to regulation reserve shortfalls reflects periods when PacifiCorp does not have sufficient resources available at short notice to compensate for intra-hour changes in load and generation, i.e., that it will not be able to deploy additional resources quickly enough. This is distinct from the resource sufficiency evaluated in the planning reserve margin study, as it is based on what resources are doing in a given interval, and not whether they are generally available to serve load. For example, in order to meet ramping requirements, regulation reserves might need to be spread among several units, rather than assigning the entire reserve amount to the unit with the highest variable cost, thereby allowing more generation from lower-cost units. The planning reserve margin study would not distinguish between these dispatch changes, as the same total quantity would be available. Similarly, resources that are providing regulation reserves cannot be used to support firm wholesale sales, because once they are dispatched up to support a sale, they will be unavailable to compensate for intra-hour increases in PacifiCorp's load or reductions in generation. In contrast, potential wholesale sales opportunities do not impact the capacity need identified in the planning reserve margin study. Resources that are providing regulation reserves can be used to support EIM exports, because they are dispatched within the hour and transfers are economically optimized in each interval to address changing conditions. This sharing of regulation reserve resources is essential to the premise of the EIM and enables the EIM diversity credits that reduce PacifiCorp's calculated regulation reserve requirement.

Q. Are the risks identified in the planning reserve margin study and the regulation reserve study additive?

A. Yes. As discussed above, these studies identify different potential conditions that could each lead to a loss of load.

Q. Are the risks in these studies the only risks customers face from resource planning?

A. No. Regulation reserves only address intra-hour changes in load, wind, and solar. While the stochastic modeling in the planning reserve study addresses additional uncertainty in load, the modeling in the 2019 IRP and 2021 IRP did not account for the additional uncertainty in wind and solar generation, as they were modeled using a single hourly profile that was identical in each year of the study horizon. Climate change and extreme weather could also increase risks associated with all of these elements.

B. 2021 IRP Modeling

Q. Sierra Club indicates that the Jim Bridger coal supply analysis from PacifiCorp's 2021 IRP could be relevant to this proceeding.[4] Please summarize the modeling of the two Jim Bridger coal supply scenarios in the 2021 IRP.

A. The Jim Bridger coal supply scenario used for the majority of the modeling conducted for the 2021 IRP included minimum annual volume requirements, and an incremental coal cost of zero, up to the minimum annual volume. This cost would be avoided if coal-fired generation at the Jim Bridger plant ceased as a result of retirement of all units. However, while any units continued coal-fired operation, the model would seek to use coal up to the minimum, even if the net benefits in a particular hour were less than the average cost of the coal.

In response to a series of Bench Requests, PacifiCorp prepared a second "No Minimum" Jim Bridger coal supply scenario, which included a modest increase in variable costs, and no annual minimum volume requirement. In this scenario, the model would only use coal when it provides a net economic benefit in a given period, i.e., every time a unit is turned on or dispatched up, it is because it is cheaper than other available options.

Q. Are both coal supply scenarios equally achievable in reality?

A. No. The primary modeling is generally consistent with Jim Bridger coal supply

[4] Sierra Club/100 Burgess/50-52.

constraints PacifiCorp has experienced in the past, so it is reasonably likely they could be achieved in actual operations. The "No Minimum" scenario did not have any minimum or maximum supply constraints. Absent ongoing mining operations, the primary suppliers of coal to Jim Bridger would be unavailable, and options for alternative sources would have significant volume restrictions and/or costs that were not represented in the "No Minimum" scenario.

Q. Sierra Club provides various confidential characterizations related to the significantly lower generation and coal consumption at Jim Bridger 3 and 4 in the "No Minimum" scenario, particularly after 2030.[5] Do these figures provide a comprehensive representation of demand for coal at Jim Bridger over time?

A. No. As indicated in Sierra Club's footnote 84, the referenced figures reflect the "ST Model" forecast for Jim Bridger 3 and 4. In the 2021 IRP, the short-term (ST) model used an hourly granularity on a deterministic basis, i.e., with a single set of assumptions, including median load and median prices. PacifiCorp also conducted stochastic analysis using a medium-term (MT) model, which had a granularity of four blocks of hours per day and assessed system costs in 50 iterations of varying load, hydro, market prices, and thermal outages. Those results are discussed in Exhibit Sierra Club/118. On average, Jim Bridger 3 and 4 coal generation in the MT model is significantly higher than in the ST model, and the individual iterations reflect a significant range of outcomes. As a result, maintaining the ability to call upon significant volumes of coal when needed appears to be valuable, and that value is embedded in the risk-adjusted results associated with the analysis. If it is not

[5] Sierra Club/100 Burgess/52.

contractually feasible to procure coal with the flexibility assumed in the "No Minimum" study, system costs in that study would increase.

Q. Would it be prudent for the Company to make long-term coal supply decisions based on the "No Minimum" ST model analysis cited by Sierra Club?

A. No. The Company's recent long-term coal supply decisions have assessed demand under a range of potential future conditions.[6] The ST model forecast cited by Sierra Club reflects only a single possible outcome, and one in which conditions are normal throughout the entire study horizon.

Q. Does the "No Minimum" analysis provide additional support for continued coal-fired operation at Jim Bridger 3 and 4?

A. Yes. Continued coal-fired operation of these units through 2037 was more economic than other available options despite assuming a relatively onerous take or pay contract would be required. The "No Minimum" scenario indicates there is significant potential for flexible coal supply arrangements to deliver greater benefits, which would make continued coal-fired operation even more economic.

Q. Is the disparity between the forecasted Jim Bridger coal-fired generation in the MT and ST model results surprising?

A. Not particularly. As noted above, the deterministic, median inputs to the ST model represent relatively uniform conditions. The stochastic MT model results indicate that the Jim Bridger coal generation would be economic and called upon in a variety of likely situations. The purpose of stochastic modeling is to identify how a portfolio

[6] This analysis is consistent with the Commission's directive to show "robust decision-making and contingency planning" with regards to CSAs. *In the Matter of PacifiCorp, d/b/a Pacific Power*, *2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 7 (Nov. 1, 2021).

and the resources it contains perform under a variety of conditions, and the results are valuable because they are different from the ST model analysis.

Q. Did PacifiCorp make any long-term coal supply commitments on the basis of the 2021 IRP modeling results or the "No Minimum" scenario?

A. No. Significant long-term coal supply commitments are made based on the specific terms and conditions over the term of the commitment and using the best available information at the time the commitment is made. The 2021 IRP and "No Minimum" scenario reflect generalized coal supply assumptions along with a variety of other inputs which were locked down a year or more ago. As a result, these scenarios can only provide an indication of areas to explore further as future coal supply arrangements are negotiated, and additional analysis would be required.

C. Jim Bridger LTFP

Q. Sierra Club criticizes the Company for using the Generation and Regulation Initiative Decision Tool (GRID) to develop the LTFP.[7] Why did the Company use GRID, instead of Aurora?

A. GRID was used for the Jim Bridger LTFP 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.

[7] Sierra Club/100, Burgess/15.

Q. Sierra Club argues that GRID's inability to accept multiple pricing tiers makes it particularly ill-suited for developing the LTFP "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."[8] Do you agree?

A. No. The Company relied on GRID for many years to set Oregon customer rates despite the fact that the model could not endogenously optimize multiple pricing tiers. To account for this fact, consistent with prior TAMs, the GRID runs used to develop the LTFP iterated dispatch tier inputs. Endogenous optimization in Aurora and iterative dispatch in GRID results in a comparable outcome and the GRID modeling approach was the same as that the Commission approved in the 2022 TAM.

Q. Sierra Club claims that the Company should have used its PLEXOS model to develop the LTFP.[9] Why didn't the Company use PLEXOS to develop the LTFP?

A. 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 IRP group receives less frequent input and configuration updates than 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 LTFP deadline. GRID, used by the Company's finance department also regularly compares coal generation forecast results to actual results and makes forecast

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[8] Sierra Club/100, Burgess/16.
[9] Sierra Club/100, Burgess/15.

adjustments as necessary. The PLEXOS model is capable of modeling coal supply options and PacifiCorp does use it for this purpose, as illustrated by the analysis supporting the Naughton CSA[10] and the Jim Bridger CSA[11], but was not able to use it to meet the Jim Bridger LTFP deadline.

Q. Notwithstanding the foregoing, why did PacifiCorp use GRID for the LTFP but PLEXOS for the evaluation that informed the new Naughton CSA?

A. PacifiCorp spent several months coordinating the modeling and negotiation of the Naughton CSA, which reflected just two coal supply scenarios. The LTFP considered six coal supply scenarios and was prepared with relatively short notice that overlapped with the preparation of PacifiCorp's 2021 IRP Update, filed on April 4, 2022. The PacifiCorp group using PLEXOS was thus unable to take on the significant scope of the LTFP within the required timeframe.

Q. Sierra Club states that "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."[12] Is this accurate?

A. Not always. Use of the full average cost for dispatch can be useful before a coal supplier has provided pricing for specific volumes, to provide an indication of the level of supply that PacifiCorp should consider acquiring. For suppliers with many potential buyers, a change in volume may not impact the price, and PacifiCorp can request any volume it desires. There are a number of suppliers of Powder River

[10] Exhibit PAC/201.
[11] Exhibit PAC/801 (Black Butte coal supply analysis).
[12] Sierra Club/100, Burgess/20-21.

Basin coal for Dave Johnston, and likewise several potential suppliers for the Hunter plant in Utah. In both cases, PacifiCorp is not the only buyer. The third-party coal suppliers for Naughton and Jim Bridger have limited buyers besides PacifiCorp, and thus their pricing is highly dependent on PacifiCorp's volume. As a result, PacifiCorp cannot expect an average price estimate from these suppliers to apply to any volume. In such instances, use of the full average cost for dispatch decisions will not provide a useful result because it is inconsistent with the supplier's cost structure.

Q. Please discuss how average cost modeling would apply to Bridger Coal Company (BCC) and Black Butte.

A. The LTFP illustrates the differences between a variety of real-world coal supply strategies. Modeling an average cost of coal, rather than an incremental cost of coal, does not accurately represent the potential savings from reduced coal consumption, either in terms of BCC incremental costs, or in terms of what a Black Butte contract could reasonably be expected to include. This is because fixed costs comprise the majority of the cost of coal from these sources and cannot be avoided by a partial reduction in coal volumes. While the entirety of the cost could be avoided at zero coal volume, this is an unlikely outcome if the average cost of coal is modeled.

Regardless, the total costs and benefits at a given volume are the most important outcome of any modeling. Where the average cost of coal varies as a function of volume, it will only be an accurate representation at one particular point (and possibly at zero volume). Combining a fixed cost of coal with an incremental cost allows for an accurate representation across a range of volumes.

Q. Do PacifiCorp's Naughton and Jim Bridger coal analyses in the 2023 TAM use average cost modeling for production cost model dispatch?

A. No. Both of these analyses were conducted using PLEXOS, which assesses the price and volume requirements of all of the tiers of available coal supply simultaneously, and does not use an average cost for dispatch decisions.

Q. Sierra Club testifies that, "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."[13] Is this true?

A. It is certainly conceivable that lower cost options could be available, and PacifiCorp could certainly have modeled abundant low-cost coal, wind, or solar resources for the 2022–2023 timeframe, but modeling inputs do not make an option feasible in reality. PacifiCorp's analysis of the Black Butte CSA, presented in Company Witness James Owen's reply testimony, includes a scenario in which the Black Butte coal supply is replaced entirely with energy from available alternatives, and demonstrates that it was not the least-cost, least-risk option.

D. Naughton CSA

Q. Did you prepare the analysis used to support the Naughton CSA?

A. Yes.

[13] Sierra Club/100, Burgess/24.

Q. Do any parties identify concerns with the Naughton CSA analysis?

A. Yes. Sierra Club identifies a concern that multiple assumption changes were made among the three scenarios used to assess the potential costs and benefits of the Naughton CSA, and that some of these changes appear to counteract each other.[14]

Q. Did PacifiCorp's Naughton CSA analysis identify the fact that the assumptions during a portion of the proposed contract term were in conflict with the expected/high/low coal demand conditions for the respective cases that were assessed?

A. Yes.[15]

Q. Would better alignment of the assumptions across the various cases during that portion of the proposed contract term have impacted the cost-effectiveness of the proposed CSA?

A. Not in a meaningful way.[16] [redacted] had a negligible impact on the cost-effectiveness of the Naughton CSA as a whole, in any coal demand case. As a result, ignoring that portion of the proposed contract term, or considering it independently of the remainder of the term, would not have impacted the conclusion in any of the cases or the overall result.

[14] Sierra Club/100 Burgess/98-99.
[15] Exhibit PAC/201 Owen/4 (Last paragraph).
[16] Exhibit PAC/201 Owen/1 (Under "Results Summary").

E. Huntington CSA

Q. Sierra Club opined that the Huntington Report should "conduct a modeling simulation that is similar to the one PacifiCorp recently conducted as part of its 2021 IRP." Do you agree?

A. No. The Huntington Report was not intended to be a substitute for the IRP process. It was intended to answer a specific question: Would it be economic for the Company [redacted] in the Huntington CSA at the present time? The Huntington Report answered this question.

Q. Should the Company consider the terms of the Huntington CSA in its IRP process, [redacted]?

A. Yes. It is appropriate to incorporate PacifiCorp's options under the Huntington CSA in the IRP. For example, in PacifiCorp's 2021 IRP modeling, no Huntington CSA costs were applied after an early retirement of the plant, which would likely be driven at least in part by assumed greenhouse gas costs. IRP modeling is intended to consider all fuel supply issues, including the limited options to support coal generation in Utah without a long-term CSA, but there are limitations. Modeling particular coal supply arrangements (i.e., pick one option to use through the end of the study horizon), fails to account for opportunities to adapt over time as conditions change. On the other hand, the range of all likely options that could be achieved over the long-term is different from the flexibility once an option with a defined contract length is committed to. The balance between these factors is necessary in any study. Generally, the IRP process benefits from allowing flexibility that could be achieved in the long-term 20-year horizon of the IRP. Where specific commitments are being considered, the details of each discrete option are modeled over a shorter horizon.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 400
Exhibit PAC/701
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Daniel J. MacNeil

PacifiCorp Response to Staff Data Request OPUC 74

June 2022

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 74

OPUC Data Request 74

Regulating Reserve Requirement – In reference to PAC/300, MacNeil/17-18, concerning the one-day-in-ten-years loss of load hours (LOLH) reliability metric:

(a) Does PacifiCorp's use of the "less restrictive" LOLH interpretation of 2.4 hours per year result in a lower NVPC rate charged to customers? If no, why is the less restrictive interpretation used?

(b) There are several different values referenced for LOLH (2.4 hours, 0.50 hours, and 1.06 LOLH per year). If 2.4 hours LOLH a year is representative of a "reliable" electric system, please explain why the Company also uses the lower 0.50 hours and 1.06 hours LOLH per year metrics to determine regulation reserve requirements?

Response to OPUC Data Request 74

(a) From a capacity planning perspective, the Company's use of a 2.4 hour per year target would consider a portfolio reliable if shortfall events with duration of eight hours each were expected to occur in three out of 10 years (24 hours in 10 years, or 2.4 hours per year). Under a one day in 10 years target, additional resources would need to be added to eliminate two of the three shortfall events, such that only one day in 10 years experienced any events. These incremental resources would result in higher customer rates to achieve the higher level of system reliability.

(b) 1.06 loss of load hours (LOLH) represents the probability of shortfalls due to resource adequacy, namely the chance that a combination of a hot summer, dry hydro conditions, and above average forced outages would leave insufficient resources for the Company to serve load and meet its operation reserve obligations. This is calculated using an hourly model, therefore, it does not capture intra-hour variation. The regulation reserve requirement based on a 0.5 LOLH only represents intra-hour forecast error relative to a forecast made in the prior hour, and not the other factors, which would impact many hours in a row. As a result, there is little or no overlap between these two sources of uncertainty and they would be additive. Because customers are agnostic to the cause of their power being shutoff, the combined risk from both types of events should not exceed the target of 2.4 hour per year.

REDACTED
Docket No. UE 400
Exhibit PAC/800
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of James Owen

June 2022

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ATTACHED EXHIBITS

Highly Confidential Exhibit PAC/801 – Black Butte Coal Supply Agreement Analysis

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

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the opening testimony of Steve Storm, filed on behalf of the Public Utility Commission of Oregon (Commission) Staff, Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC), and Ed Burgess, filed on behalf of the Sierra Club.

Q. Please summarize your testimony.

A. In my testimony I first provide a review of how coal costs were revised in the Transition Adjustment Mechanism (TAM) Reply Update, and briefly describe the analysis the Company completed prior to executing the Black Butte coal supply agreement (CSA). Additionally, I respond to the following arguments from Staff, AWEC, and Sierra Club:

- I respond to Staff's concerns by explaining PacifiCorp's coal inventory management at Naughton, providing an overview of the history and purpose of the Jim Bridger Long-Term Fuel Supply Plan and Jim Bridger coal costs, and discuss the presentation of coal costs in this testimony;
- I explain why AWEC misunderstands the Hayden CSA, and respond to their concerns regarding the coal costs at the Trapper mine;

- Finally, I address Sierra Club's concerns regarding the Jim Bridger Long-Term Fuel Supply Plan (2022 Fuel Plan) and coal costs at Jim Bridger and Naughton.

II. TAM REPLY UPDATE TO COAL COSTS

Q. Does the TAM Reply Update include any changes to fuel costs or volumes when compared to the 2023 TAM Initial Filing?

A. Yes. The following tables compare values from the 2023 TAM Reply Update versus the 2023 TAM Initial Filing. Confidential Table 1 shows updates to the CSA prices per ton received from each supplier:

Confidential Table 1

[redacted]

Confidential Table 2 compares the tons of coal consumed:

Confidential Table 2

[redacted]

Table 3 details the changes to total coal fuel costs:

Table 3

Fuel Cost ($,millions)				
Plant	**2023 TAM Reply**	**2023 TAM Direct**	**Variance-$**	**Variance-%**
Colstrip	20.0	18.4	1.6	8%
Craig	23.2	14.4	8.8	61%
Dave Johnston	67.1	63.8	3.4	5%
Hayden	10.2	10.2	0.0	0%
Hunter	137.1	126.2	10.9	9%
Huntington	120.1	110.7	9.5	9%
Jim Bridger	201.2	196.1	5.1	3%
Naughton	32.9	28.0	4.9	17%
Wyodak	33.8	32.3	1.5	5%
Total	645.6	600.0	45.6	8%

Coal fuel costs have increased by $45.6 million, driven mainly by an increased coal generation forecast in the updated Aurora model results.

Confidential Table 4 summarizes the CSAs in effect for 2023 as of the filing of this Reply Update:

Confidential Table 4

[redacted]

III. BLACK BUTTE CSA

Q. Has PacifiCorp entered into any new CSAs since its Initial Filing in the 2023 TAM?

A. Yes. PacifiCorp entered into a new CSA with Black Butte Coal Company on June 17, 2022, to supply coal for the Jim Bridger plant (Black Butte CSA). Consistent with the requirements of the order from the 2022 TAM,[1] my testimony and the corresponding exhibit provide additional information demonstrating the prudence of the Black Butte CSA.

Q. Please provide some background on the Jim Bridger plant and its planned future operations.

A. 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 percent) and Idaho Power Company (Idaho Power)

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 6-7 (Nov. 1, 2021).

(33.3 percent). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Consistent with the findings of the 2021 Integrated Resource Plan (IRP), as well as environmental compliance requirements, the 2022 Fuel Plan assumes Jim Bridger Units 1 and 2 will stop consuming coal by December 31, 2023, and convert to natural gas-fired operation in 2024. Jim Bridger Units 3 and 4 will continue to operate on coal until December 31, 2037.

Q. What is the term of the Black Butte CSA?

A. The term of the Black Butte CSA is [redacted]. This term is consistent with PacifiCorp's current practice of limiting its CSAs to five years or less, based on business judgment, to maintain flexibility in fuel supply and generation planning.

Q. What are the terms for annual volume and pricing in the Black Butte CSA?

A. Annual volume and pricing is as follows:

Year	Minimum Tons	Maximum Tons	Tier 1 Price/Ton	Tier 2 Price/Ton
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. Does the Black Butte CSA include a minimum take requirement?

A. Yes. Like the previous CSA, the Black Butte CSA is a minimum take agreement. PacifiCorp would not have been able to secure the necessary coal supply at a favorable contract price without agreeing to a minimum take obligation as part of the Black Butte CSA.

Q. In the order from the 2022 TAM, the Commission identified several elements that should be addressed when presenting a new CSA. What are those elements?

A. The 2022 order stated the following items should be addressed when PacifiCorp presents a new CSA:

- PacifiCorp will need to explain in detail how economic cycling was considered when deciding on minimum take levels in the contract, a comparison of the MMBtu level from generation analysis to the contracted-for level, and to provide the workpapers used in analysis of the generation forecasts for CSA negotiations.[2]
- PacifiCorp will need to explain how it incorporates its IRP planning into its TAM-reviewed fuel contracts, or its management of those contracts.[3]
- PacifiCorp will need to show it considered future costs in multiyear contracts, especially given that its plans for operating a plant generally would be expected to show declining production before retirement.[4]
- PacifiCorp will need to explain how it is allowing for an orderly sequence towards retirement and ensuring flexibility for reduced capacity factors and consumption of the coal pile, and how it will manage the contract in the event that circumstances change from those expected when it was signed.[5]

Q. Has PacifiCorp conducted an analysis for the Black Butte CSA that includes these elements?

A. Yes; please refer to Highly Confidential Exhibit PAC/801 which contains an

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[2] Order No. 21-379 at 5.
[3] *Id.* at 7.
[4] *Id.*
[5] *Id.*

overview and background of the Black Butte CSA and the economic analysis supporting the Black Butte CSA. These documents describe in detail the Black Butte CSA and PacifiCorp's economic analysis and demonstrate the prudence of PacifiCorp's execution of the Black Butte CSA. Highly Confidential Exhibit PAC/801 also demonstrates how PacifiCorp incorporated IRP-type planning and modeling into the decision process relating to the Black Butte CSA.

Q. Does the new Black Butte CSA reduce coal costs in the Reply Update?

A. Yes. The Black Butte CSA includes more favorable terms than the estimate for Black Butte coal supply reflected in the Initial Filing. The Reply Update reflects the cost savings associated with the new CSA.

IV. RESPONSE TO STAFF

A. Naughton CSA

Q. Please describe Staff's proposed adjustment related to the new Naughton CSA.

A. Staff does not appear to dispute the prudence of the new CSA at Naughton. However, Staff recommends a "reduction in allowed expense of $463 thousand for the 2023 TAM, based on [Staff's] analysis of an alternative annual pattern in coal purchases and pile depletion that is within the maximum/minimum range for all years, and results in a $463 thousand lower present value of purchases when valued as of January 1, 2023."[6]

Q. Is Staff's adjustment reasonable?

A. No. Staff's recommendation is contrary to the Company's longstanding coal inventory policies and the proposed disallowance is inappropriate. PacifiCorp's coal

[6] Staff/600, Storm/11.

inventory policy is based on the expertise and analysis performed by a third-party to ensure coal inventories are adequate to provide an economic and reliable supply of coal to generating stations. The Company's coal inventory policy, when applied at the Naughton plant establishes a target range of [redacted] days burn and a maximum inventory of [redacted]. As identified in PacifiCorp's Highly Confidential Exhibit PAC/201, Staff's recommended Naughton plant coal inventory levels would decrease from an estimated [redacted] at year-end 2021 to only [redacted] at year-end 2022, [redacted] at year-end 2023 and [redacted] at year-end 2024. In contrast, PacifiCorp's forecast based on its coal inventory policy projects a decrease from [redacted] at year-end 2021 to [redacted] year-end 2022. PacifiCorp also forecasts coal inventory to decrease to [redacted] at year-end 2023 and [redacted] at year-end 2024 in advance of the plant ceasing coal operation. Additionally, Staff's proposed disallowance represents the net present value of a fuel procurement strategy that has a significantly higher risk profile due to extremely low coal inventories and the inclusion of costs in 2022, 2024, and 2025 that are outside the test period. These low coal inventories could expose customers to significant risk due to volatility in coal prices and could present possible reliability issues. Naughton does not have significant access to alternative sources of coal, and it would be difficult to maintain the coal pile and generation in the event of supply interruptions if Staff's recommendations were adopted.

Q. Has the Commission previously examined the reasonableness of the Company's coal stockpile management practices and inventory policy?

A. Yes. In the 2018 TAM, Staff recommended an adjustment related to the Cholla plant that was based on Staff's claim that the Company had mismanaged its coal stockpile volumes thereby incurring unreasonable liquidated damages under the plant's CSA.[7] In response, the Company testified that if it were to purchase coal at the level assumed in Staff's adjustment to avoid liquidated damages, the plant's stockpile would continue to have volumes well above its target level.[8] The Company explained that while coal stockpiles naturally fluctuate over time, PacifiCorp works to maintain target levels to avoid both the incremental costs of maintaining an unnecessarily large stockpile, and the operational issues and risks associated with maintaining a stockpile that is too small.

The Commission rejected Staff's recommended adjustment in that case noting that the stockpile inventory was close to its historical target level and therefore reasonable.

Q. Did the Commission provide any additional direction regarding stockpile inventories in the 2018 TAM?

A. Yes. The Commission directed PacifiCorp to submit an updated coal inventory report.[9]

Q. Did PacifiCorp comply with the Commission's directive?

A. Yes. The PacifiCorp Coal Inventory Policies and Procedures was updated March 20, 2018, and filed in the 2019 TAM.[10] The PacifiCorp Coal Inventory Policies and Procedures set forth the current policies, procedures, and practices developed by PacifiCorp for the management of coal stockpiles by the Company's fuels

[7] Order No. 17-444 at 12.
[8] *See* Docket No. UE 323, PAC/600, Ralston/8.
[9] Order No. 17-444 at 13.
[10] Docket No. UE 339, PAC/200, Ralston/6, PAC/202, and PAC/203.

department. PacifiCorp retained the consulting firm of RPM Global (RPM) to update their prior inventory studies from 2009-2010 and 2015. The 2018 RPM coal inventory study was filed in the 2019 TAM.

Q. Did any party object to the Coal Inventory Policies and Procedures in the 2019 TAM?

A. No. Additionally, PacifiCorp conducted a new report on maintaining its coal inventory in 2021 using the same methodologies and third-party consultant. PacifiCorp continues to review (and refresh if prudent) its coal inventory policies on an annual basis.

B. Jim Bridger Long-Term Fuel Supply Plan

Q. Please provide an overview of the Company's preliminary 2022 Fuel Plan, which was filed in this docket on April 15, 2022.

A. The preliminary 2022 Fuel Plan reflects an initial evaluation of how PacifiCorp can best meet the fueling needs of the Jim Bridger plant throughout the operational life of the plant, given the natural gas conversion of Jim Bridger Units 1 and 2 in 2024, reductions to coal generation as a result of increased renewable generation in the Company's portfolio, and other changing circumstances affecting the plant over the next several years.

Q. Does PacifiCorp intend to conduct additional evaluation of Jim Bridger's long-term fuel supply plan in the 2023 IRP?

A. Yes. PacifiCorp has committed through deliberations in the 2021 IRP proceeding in Oregon (docket LC 77) to complete a revised long-term fuel plan and include the plan details as assumptions aligned with or as a part of 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 the 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 carbon capture utilization and sequestration (CCUS), conversion to natural gas and/or other alternative fuels, and early retirement. Going forward, the Company anticipates preparing long-term fueling plans for the Jim Bridger plant as necessary to inform and align with future IRP filings.

Q. As background, has the Commission previously addressed the Company's fueling strategy for the Jim Bridger plant in the TAM?

A. Yes. Issues regarding PacifiCorp's fueling strategy for the Jim Bridger plant have been raised multiple times over the years, including in the dockets UE 264 (2014 TAM), UE 307 (2017 TAM), UE 323 (2018 TAM), UE 339 (2019 TAM), UE 356 (2020 TAM), and UE 390 (2022 TAM) and the Commission has repeatedly affirmed the reasonableness of the Company's strategy for fueling the plant.

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

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

The Commission rejected this adjustment, approving PacifiCorp's fueling strategy for the Jim Bridger plant as "fair, just and reasonable." Specifically, the Commission found there was no available lower-cost market alternative to replace BCC coal. The Commission was not persuaded that Black Butte coal would be available in the excess capacity required or that it would be less expensive than the BCC contract price for the period in question.[11]

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

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

At the suggestion of PacifiCorp, Staff, and the Oregon Citizens' Utility Board (CUB), the Commission directed the Company to prepare "a periodic fuel supply plan that compares affiliate mine fuel supply to other alternative fuel supply options, including market alternatives."[12]

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

A. In the 2017 TAM, ICNU and Staff challenged Jim Bridger fuel costs on the basis that BCC coal costs were higher than market alternatives, albeit this time with reference to coal from the Powder River Basin rather than the Black Butte mine. Staff argued the

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[11] *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387, at 5-7 (Oct. 28, 2013).
[12] *Id.* at 7.

Company was imprudent in failing to consider market alternatives, while ICNU revived its arguments from the 2014 TAM regarding the lower of cost or market rule. The Commission rejected both sets of arguments, reaffirming the reasonableness of PacifiCorp's fueling strategy.[13]

Q. Did the Commission make any other relevant rulings with respect to Jim Bridger fuel supply in the 2017 TAM?

A. Yes. The Commission directed the Company to delay filing its long-term fuel supply plan for the Jim Bridger plant, and instead meet informally with the parties to discuss the information needed to provide a meaningful evaluation of the long-term fuel supply plan for the Jim Bridger plant in future TAM proceedings.[14]

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

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

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

A. In the 2018 TAM, PacifiCorp reported to the Commission on two workshops held

[13] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482, at 5-8 (Dec. 20, 2016).
[14] *Id.* at 7.
[15] Order No. 16-482 at 9.

after the conclusion of the 2017 TAM, which focused on the Jim Bridger fueling strategy. The Company also reported that it had identified different fuel plan scenarios, selected the least-cost, least-risk option, and was on track to complete its long-term fuel plan by the target date of December 2017. The Commission approved PacifiCorp's plans to finalize the long-term fuel plan and directed that the long-term fuel plan be attached to testimony in the next TAM proceeding, which was the 2019 TAM.

Q. In the 2018 TAM, did the Commission also review the Company's near-term fuel strategy for the Jim Bridger plant, including execution of the Black Butte CSA that preceded the new agreement presented in this case?

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

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

A. Yes. Sierra Club proposed an adjustment related to the Naughton CSA, which it later withdrew.[17] Sierra Club also recommended that the Commission direct PacifiCorp to

[16] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444, at 13-14 (Nov. 1, 2017).
[17] *See In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Sierra Club/200, Vitolo/2 (Aug. 2, 2017).

refrain from entering into new coal supply contracts with minimum-take provisions. Ultimately, Sierra Club and PacifiCorp came to an understanding, and these recommendations were withdrawn based on an agreement to conduct a workshop to address the following issues:[18]

- PacifiCorp's process by which the terms and conditions of long-term coal contracts are developed, negotiated and approved, and how the Company accounts for plant fuel requirements when negotiating long-term contracts or coal mine investment decisions.
- PacifiCorp's process for managing risk in long-term coal contracts related to: (a) price; (b) contract length; (c) minimum take provisions; (d) liquidated damages; and (e) changing electricity market conditions.
- How long-term coal contract provisions impact dispatch decisions in PacifiCorp's Generation and Regulation Initiative Decision Tool model (GRID), commitment decisions, and long-term system modeling decisions.
- How (a) long-term coal contracts, (b) fuel transportation contracts, and (c) spot market coal fuel purchases are each reviewed before the Commission.
- The potential development of a method to reflect variable operation and maintenance (O&M) in Net Power Costs (NPC), including classification of which O&M costs should be treated as variable and the treatment of variable O&M in rates.
- Coal plant economic cycling.

[18] *See* Order No. 17-444 at 11.

Q. When did PacifiCorp convene this workshop?

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

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

A. In the 2019 TAM, the Company submitted testimony summarizing the results of PacifiCorp's February 23, 2018 workshop on coal supply contracts and dispatch issues and included the presentation from the workshop as an exhibit to its testimony.[19] In the Company's testimony, it also included PacifiCorp's long-term fuel plan for the Jim Bridger plant (2018 Fuel Plan),[20] and provided details on the 2018 Black Butte CSA. Consistent with PacifiCorp's near-term fuel strategy approved in the 2018 TAM and outlined in the 2018 Fuel Plan, the 2018 Black Butte CSA was executed on February 6, 2018, with a 44-month term, beginning May 1, 2018, and ending December 31, 2021. The Company's testimony also explained that it had the option under the contract to extend the term an additional four months, through April 30, 2022,[21] with no change in volume or price.

Q. What happened in the 2019 TAM?

A. Sierra Club did not intervene in the case, and no party objected to the 2018 Black Butte CSA. The Commission approved a stipulation in which the parties agreed PacifiCorp would complete additional analysis with respect to the 2018 Fuel Plan. Specifically, the Company agreed to update its analysis using 2029 rather than 2037

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[19] Docket No. UE 339, Exhibit PAC/201.
[20] Docket No. UE 339, Exhibit PAC/204.
[21] On February 21, 2020, the Company extended the term of the 2018 Black Butte CSA to April 30, 2022. Black Butte was unable to deliver the coal required by April 30, 2022. As a result, the Company and Black Butte agreed to extend the term to allow for delivery of the coal. The final coal purchased under the 2018 Black Butte CSA was delivered to the Jim Bridger plant on June 17, 2022.

as an end date for the useful life of the plant, for the purpose of evaluating whether the Jim Bridger fueling strategy is reasonable if the plant life is shortened for Oregon Senate Bill 1547 compliance. The parties further agreed to set parameters for this analysis and to include the analysis in the 2020 TAM if it modified the 2018 Fuel Plan.[22] In addition, the parties agreed to PacifiCorp's proposals to model economic cycling of coal plants and to include variable O&M in modeling coal dispatch in GRID.

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

A. In its testimony in the 2020 TAM, the Company included an update to the 2018 Fuel Plan that reflected a shortened plant life of January 1, 2030, instead of 2037.[23] This alternative analysis resulted in the same fuel plan being selected as the least-cost, least-risk option, validating the reasonableness of the Company's Jim Bridger fueling strategy.

Q. Did any party object to the revised Jim Bridger fuel plan in the 2020 TAM proceeding?

A. No.[24]

Q. How was the 2020 TAM resolved?

A. The Commission approved an all-party stipulation in which the only coal-related provision was an agreement to hold a workshop on Jim Bridger depreciation issues. In its order, the Commission noted that it had closely tracked Jim Bridger costs for several years and directed PacifiCorp to update its Jim Bridger fuel plan, given the

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[22] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, at 4 (Oct. 26, 2018).
[23] Docket No. UE 339, Exhibit PAC/201.
[24] Sierra Club was not an intervenor in the 2020 TAM proceeding.

earlier end-of-life dates in its 2019 IRP. Specifically, the Commission asked PacifiCorp to explain how the Company is planning ahead with more flexible fueling arrangements to avoid minimum take penalties.[25]

The Commission subsequently amended its order, at PacifiCorp's request, to allow for testimony and a Commission workshop in the 2021 TAM, rather than developing an updated fuel plan. The Company committed to providing information at the Commission workshop on "minimum take penalties, and the flexibility of the fueling arrangements with company-owned and third-party coal suppliers in light of earlier end of life dates."[26]

Q. Did PacifiCorp comply with these orders?

A. Yes.

Q. How were Jim Bridger plant coal costs addressed in the 2022 TAM?

A. In the 2022 TAM, certain parties challenged the dispatch practices used for the Jim Bridger plant, among other issues. The Commission did not approve any recommended adjustments to how the Company dispatches the plant. But the Commission directed PacifiCorp to "update and file the Jim Bridger Long Term Fuel Plan document in the 2023 TAM."[27]

Q. What is the purpose of the 2022 Fuel Plan?

A. The purpose of the 2022 Fuel Plan is to provide a preliminary evaluation of how to best meet the fueling needs of the Jim Bridger plant given the natural gas conversion of Jim Bridger Units 1 and 2 in 2024, reductions to coal generation as a result of

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[25] *In the Matter of PacifiCorp, dba Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351, at 8 (Oct. 30, 2019).
[26] Docket No. UE 356, Order No. 20-023, at 1-2 (Jan. 22, 2020).
[27] Order No. 21-379 at 14.

increased renewable generation in the Company's portfolio, and other changing circumstances affecting the plant over the next several years. The 2022 Fuel Plan is not intended to be a finalized management strategy, which aligns with the direction provided by the commission[28].

Q. How did the Company develop the 2022 Fuel Plan?

A. 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 the consequences of fueling the Jim Bridger plant solely from Bridger mine or solely from Black Butte mine, after 2023.

Q. What fueling options were evaluated in the 2022 Fuel Plan?

A. The fueling options considered varying delivery schedules sourced from the 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 Company developed and evaluated five primary Jim Bridger plant coal fueling options:

- **Scenario 1** [redacted]
- **Scenario 2** [redacted]

[28] In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism, Docket No. UE 390, Order No. 22-065 at 5

[redacted]

- **Scenario 3** [redacted]

- **Scenario 4** [redacted].

- **Scenario 5** [redacted]

Q. Why do each of the five scenarios assume PacifiCorp [redacted]?

A. PacifiCorp will be operating all four Jim Bridger units on coal until the end of 2023, when units 1 and 2 will cease operating on coal and will be converted to natural gas operation. [redacted]

Q. How did the Company develop its pricing assumptions used in the 2022 Fuel Plan?

A. 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. The 2022 Fuel Plan provides estimated volumes and rail rates for transportation services based on prior agreements with the Union Pacific Railroad 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.

Q. How did the Company evaluate each of the five scenarios?

A. 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 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 official 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 Environmental Protection Agency emissions requirements, such as the Ozone Transport Rule, or state-based requirements to evaluate CCUS implementation at Jim Bridger.

Q. Did the Company modify its economic analysis in the 2022 Fuel Plan relative to prior plans submitted to the Commission?

A. Yes. 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 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.

Q. Did the Company's economic analysis consider a 2029 closure date for the Jim Bridger plant?

A. Yes. The 2022 Fuel Plan includes the results of PVRR analysis assuming a 2037 and 2029 plant closure date.

Q. Did the 2022 Fuel Plan evaluate the risks associated with each of the five fueling scenarios?

A. Yes. The 2022 Fuel Plan analyzed four risk profile categories: (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.

Q. What were the results of the Company's evaluation of the five fueling scenarios?

A. The results of the PVRR analysis and risk evaluation indicate that [redacted] is the current least-cost, risk-adjusted option under either a 2029 or 2037 closure date. The benefits of pursuing [redacted] as the long-term fueling strategy for the Jim Bridger plant include the following:

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

Although [redacted] 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.

Q. Did the Company perform any additional sensitivities in the 2022 Fuel Plan?

A. Yes. In the 2022 TAM, the 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."[29] To comply with this request, the 2022 Fuel Plan considered a scenario that uses an average cost to dispatch the Jim Bridger plant instead of an incremental cost. This average cost scenario is Scenario 6 in the 2022 Fuel Plan and that scenario uses the one dragline Bridger mine plan's average cost [redacted] to dispatch the Jim Bridger plant.

Q. Did the average cost scenario (Scenario 6) outperform [redacted]?

A. No. Using either a 2029 or 2037 assumed closure date, Scenario 6 resulted in a higher cost. 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,

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

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 investments 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 and practical operating limits. By arbitrarily dispatching Bridger plant on an average basis rather than an incremental basis, customers are 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 the [redacted], clearly demonstrates the value the customer loses from choosing to dispatch a plant on an average, rather than an incremental, cost basis.

Q. Staff testifies that the 2022 Fuel Plan "fell short" because it did not include "certain conditional analyses," such as the "inclusion of what the Company's costs would be under alternative terms and conditions of a set of future CSAs. . . with respect to the plant's closure."[30] Does Staff's recommendation mischaracterize the purpose of the long-term fuel plan?

A. Yes, the purpose of the long-term fuel plan is to determine the optimal fueling strategy to support the resource mix as determined by the IRP. The IRP considers resource mix alternatives and determines appropriate retirement dates. As discussed above, the 2022 Fuel Plan prepared in April 2022 was a preliminary report. PacifiCorp will be updating the analysis and it will be evaluated and modeled in IRP sensitivities and analyses.

C. Jim Bridger Coal Costs

Q. Staff does not propose an adjustment to Jim Bridger coal costs but testifies that PacifiCorp's testimony and exhibits do not demonstrate that both coal production and final reclamation activities should be considered when evaluating the prudence of operating costs incurred at BCC.[31] Why must both coal production and reclamation activities be considered?

A. Individual cost components listed in BCC operating reports such as labor/benefits, materials/supplies and outside services include the costs incurred to produce coal and complete final reclamation activities. Confidential Exhibit PAC/202 projects that BCC will spend [redacted] to produce [redacted] of coal and move [redacted] cubic yards of final reclamation material in 2023. Included in the total

[30] Staff/600, Storm/29.
[31] Staff/600, Storm/19.

[redacted] total is [redacted] for projected final reclamation costs. The [redacted] is comprised of labor/benefit [redacted], materials/supplies [redacted], outside services [redacted] and other miscellaneous costs [redacted] that are not included in the cost of coal. Dividing individual cost components by only tons delivered provides an inaccurate and meaningless number.

D. Future TAM Filings

Q. Please describe Staff's recommendation for future TAM filings related to third-party CSAs.

A. First, Staff recommends that the Company include a single table showing a compilation of changes in prices, volumes, costs, and the percent changes to each item between TAM filings.[32]

Second, Staff recommends that the single table summarizing third-party CSAs also include the following:

> 1. For those plants supplied by a third party, list the term of the CSA valid for the TAM proceeding at hand.
>
> 2. For those coal-fueled plants having a "common closure" date for coal operations that is within the term of the CSA applicable to the TAM proceeding at hand, provide an analysis of the Company's plan to optimize the use of the coal pile over the time remaining until closure. Information regarding minimums, maximums, prices, and annual coal pile inventory should be included in the table.[33]

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

A. The Company agrees to provide the information in tabular form as requested by Staff showing a compilation of changes in prices, volumes and total costs, with percentage changes to each item. In fact, PacifiCorp has implemented this new format for this

[32] Staff/600, Storm/14-15.
[33] Staff/600, Storm/15.

Reply Update. With regards to implementing additional reporting for existing CSAs, as the Company has described above, the Commission has found the Company's inventory practices prudent and additional reporting should not be necessary.

V. RESPONSE TO AWEC

A. Hayden CSA

Q. AWEC claims that the Company "did not perform any economic analysis with respect to the new" Hayden CSA.[34] Is that true?

A. Not exactly. First, PacifiCorp did not execute a new CSA for Hayden. Rather, the existing CSA had [redacted], which the Company exercised, in conjunction with the plant's co-owners. Second, PacifiCorp explained in discovery that the Hayden CSA [redacted] referenced above only gave the plant owners, including PacifiCorp, [redacted] an economic analysis would have served no meaningful purpose.

Q. AWEC claims that the Hayden CSA is imprudent because "Hayden is scheduled to be depreciated and removed from rates in Oregon at the end of 2023."[35] How do you respond?

A. First, it is important to reiterate that there is no "new" CSA for Hayden, contrary to

[34] AWEC/100, Mullins/17.
[35] AWEC/100, Mullins/17.

AWEC's testimony. The CSA at issue in this case is the same one that has been in effect since January 1, 2012.

Second, it is my understanding that Oregon's current depreciable life for Hayden extends to the end of 2023 but the Company has requested an extension of that depreciable life in its currently pending general rate case to coordinate the depreciable life with the retirement dates for the plant. It's also important to note that the depreciable life does not constitute an Oregon exit date for the resource.

B. Craig Coal Costs

Q. AWEC recommends that PacifiCorp provide additional information to "substantiate the costs from the Trapper Mine" and "provide further information on the budget process and explain why the information" that AWEC previously requested is unavailable.[36] How do you respond?

A. The Trapper Mine regularly provides financial statements to PacifiCorp, and these have been provided to AWEC when requested. PacifiCorp continues to work with Trapper Mine to respond to data requests as appropriate. However, PacifiCorp has included these costs with a similar level of detail in previous TAM filings and the costs have been deemed prudent. As such, no disallowance of these costs is appropriate.

Q. AWEC states it was concerned about the accuracy of the budget information provided by the Company because it was several years out of date. How do you respond?

A. It is not entirely clear why AWEC claims the budget is several years out of date. A

[36] AWEC/100, Mullins/19.

note in the workpaper for the Craig plant states the information was received in June 2021 and was the most recent information available at the time of the 2023 TAM Initial Filing.

VI. RESPONSE TO SIERRA CLUB

A. Jim Bridger Long-Term Fuel Supply Plan

Q. Sierra Club claims that the 2022 Fuel Plan improperly included minimum take volumes from BCC and Black Butte in 2023.[37] Why did the Company assume minimum take volumes for BCC and Black Butte in 2023?

A. In the indicative pricing discussions for Jim Bridger, the third-party vendors indicated that any CSA would include a minimum purchase obligation. Nearly all coal supply contracts have minimum purchase obligations to provide assurance to coal suppliers that they will be able to recover the significant investment costs to produce coal and to maintain an adequate workforce. Furthermore, CSAs that have a higher minimum purchase obligation typically result in a lower contract price per ton. As a result, a CSA that has a prudently structured minimum purchase obligation will often result in lower overall fuel costs. Lastly, the minimum take volumes assumed for the 2023 TAM were comparable to or less than prior contract minimums, which the Commission found reasonable.

[37] Sierra Club/100, Burgess/19.

Q. Why did PacifiCorp not use average cost modeling for BCC and Black Butte in the 2022 Fuel Plan, which was the modeling used to evaluate other CSAs, like the Hunter and Dave Johnston CSAs that were reviewed in the 2023 TAM?[38]

A. As discussed above, the Company included a scenario (Scenario 6) in the 2022 Fuel Plan that used average cost dispatch, but that scenario was not least-cost, least-risk.

Q. Sierra Club claims that the Company did not study the impact of fueling Jim Bridger solely from BCC, which the Commission encouraged in its order in the 2022 TAM.[39] Is this true?

A. No. The forecasted fuel burns used in the 2022 Fuel Plan exceeded BCC's potential production level, which means that the Company must seek additional coal supply beyond just the Bridger mine. As the Company explained in discovery, because the underground mine was closed in 2021, BCC's total production capacity decreased below the level required to fuel Jim Bridger while all four units are operating on coal.

Q. Sierra Club claims that the amount of generation in the average cost dispatch scenario (Scenario 6) for 2022 is the same as the amount of generation in the scenarios that used an incremental dispatch price.[40] Why is that so?

A. For all scenarios, the 2022 Fuel Plan used the most current short-term forecast for 2022 because it does not represent a period of time where significant changes are expected to occur.

[38] Sierra Club/100, Burgess/20-21.
[39] Sierra Club/100, Burgess/22.
[40] Sierra Club/100, Burgess/23.

Q. Sierra Club also claims that Scenario 6 includes an incorrect base volume of Black Butte coal because it was different from the base volume used in the other scenarios.[41] Why is that?

A. The different scenarios show varying base volumes with different prices as provided by Black Butte's indicative pricing. This is the best information PacifiCorp had available at the time of the development of the scenarios.

Q. Sierra Club claims that Scenario 6 also shows no incremental coal is needed in 2022 or 2023, which suggests that an optimum dispatch scenario could rely on less coal than the Company modeled.[42] How do you respond?

A. Sierra Club's definition of "optimum" appears to simply mean the lowest possible volume of coal. PacifiCorp does not agree with this characterization and would define optimum dispatch to be based on costs and benefits to customers. Scenario 6 was the highest cost scenario where [redacted].

Q. Sierra Club testifies that, "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."[43] Is this true?

A. No. Without Black Butte, the necessary replacement power would come from higher-cost incremental Company resources or higher-cost market purchases. This is discussed in further detail in the reply testimony of Company witness Ramon Mitchell.

[41] Sierra Club/100, Burgess/24.
[42] Sierra Club/100, Burgess/24.
[43] Sierra Club/100, Burgess/24.

Q. Sierra Club questions whether all the costs of BCC are included in the 2022 Fuel Plan, including mine costs that are recovered outside the TAM.[44] How do you respond?

A. Sierra Club's speculation about BCC costs is incorrect. The 2022 Fuel Plan compares the PVRR for each fueling scenario evaluated. The PVRR includes not only NPCs that are typically included in the TAM but also mine ownership costs, such as return on investment.

Q. Sierra Club also claims that the generation forecast used in the 2022 Fuel Plan differed from the forecast used in the 2021 IRP.[45] Sierra Club specifically points out that the 2023 generation forecast used in the Company's 2021 IRP is [redacted] than the generation forecast in the 2022 Fuel Plan.[46] How do you account for the differences?

A. There are several reasons that the generation forecast developed in 2021 would be different from the updated forecast used in the 2022 Fuel Plan. Most notably, the Company's forward price curve used in the 2022 Fuel Plan includes updated power and natural gas market pricing, while the forward price curve used to develop the 2021 IRP was from March 31, 2021, during a time of lower forecasted power and natural gas market prices.

Second, the generation forecast that Sierra Club is referring to "in the Company's 2021 IRP" is actually the No Minimum Scenario, not a scenario used to develop the 2021 IRP Preferred Portfolio. This No Minimum Scenario was not

[44] Sierra Club/100, Burgess/25.
[45] Sierra Club/100, Burgess/26.
[46] Sierra Club/100, Burgess/26.

developed "in the Company's 2021 IRP", rather it was run several months after the 2021 IRP was published, during the Oregon IRP proceeding (docket LC 77). The Company has provided additional information below on the deficiencies of the 2021 IRP No Minimum Scenario. For Sierra Club to attempt to use this scenario as a benchmark is flawed.

Q. Sierra Club claims that the 2022 Fuel Plan overstates the total coal deliveries to Jim Bridger as compared to a scenario that was modeled subsequent to the 2021 IRP that assumed there were no contractual limits applicable to coal procured for Jim Bridger (the No Minimum Scenario).[47] Is it reasonable to compare the 2022 Fuel Plan to the No Minimum Scenario?

A. No. The purpose of the 2022 Fuel Plan is to determine the least-cost, risk-adjusted coal supply evaluated on a multi-year basis. The 2022 Fuel Plan is a preliminary plan designed to ensure that fuel supplies are fair, just, and reasonable. The No Minimum Scenario, on the other hand, was a PLEXOS model run that included no take or pay minimums for Jim Bridger and was a hypothetical model run performed at the request of the Commission. The No Minimum Scenario evaluated assumptions that are not operationally practical or feasible, as PacifiCorp explained when it provided the results of the No Minimum Scenario. Therefore, the No Minimum Scenario was not considered for the 2022 Fuel Plan.

Q. How does the theoretical No Minimum Scenario include assumptions that are unrealistic in the actual operation of the Jim Bridger plant?

A. First, the scenarios assumed no contractual obligations of any kind for future fueling

[47] Sierra Club/100, Burgess/28.

beyond current contracts. This assumption is not realistic in practice because coal suppliers require assurance that they 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.

Second, the scenario assumes that large volumes of coal could be received from the SPRB without significant capital investment to retrofit the plant for the safe delivery and handling of this coal. However, studies to determine the additional capital investment at Jim Bridger to enable deliveries of sufficient SPRB coal to fuel the plant were calculated in the 2018 Fuel Plan. The studies conducted in 2018, and refreshed in 2019, estimated that [redacted] in capital would need to be spent to allow for a SPRB conversion. [redacted] in capital exceeds the benefits associated with these scenarios. In summary, the savings in these scenarios are illusory because the Company cannot produce coal at BCC without covering its capital, operating, and reclamation costs, nor can the Company obtain third-party supplies for Jim Bridger without contractual obligations of any kind, and in the case of SPRB coal, without significant capital investment.

Q. Sierra Club questions whether the Company performed any economic analysis of lower BCC production levels for 2023; in particular, Sierra Club claims that the Company's current 2023 mine plan assumes approximately [redacted] tons of BCC production but that the Company also considered a scenario where only [redacted] tons was produced.[48] Is that correct?

A. No. Sierra Club's implication that reducing BCC volumes would reduce NPC is entirely unsupported. The 2022 Fuel Plan examined three different levels of BCC production and the results showed that overall NPC decreased as BCC volumes increased, which undermines Sierra Club's argument that lower BCC volumes would reduce NPC.

Q. Sierra Club claims that the Company can essentially mine through 2025, then close BCC and rely on stockpiled supplies to fuel the Jim Bridger plant through 2037.[49] Is this true?

A. No. PacifiCorp did not evaluate an accelerated BCC mine closure plan that assumed the Jim Bridger plant would be fueled only from stockpiled coal. This assumption would likely force the Jim Bridger plant to shutter operations in less than one year and force the Company to purchase power at higher rates, which would harm customers.

[48] Sierra Club/100, Burgess/29.
[49] Sierra Club/100, Burgess/29.

Q. Sierra Club recommends that the Company provide an updated 2022 Fuel Plan annually in each TAM.[50] Is this a reasonable recommendation?

A. No. As described above, one of the purposes of the 2022 Fuel Plan is to inform the biennial IRP filing. Annual updates are unnecessary.

B. Jim Bridger Coal Costs

Q. Please describe Sierra Club's recommendation regarding Jim Bridger coal costs.

A. First, Sierra Club recommends 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."[51]

Second, Sierra Club recommends 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."[52]

Q. What is the current status of the Black Butte CSA?

A. The Company executed the Black Butte CSA on June 17, 2022. Attached to my testimony as Highly Confidential Exhibit PAC/801 is the Company's analysis demonstrating the prudence of the agreement. The Reply Update addressed above incorporates the terms of the newly executed CSA.

[50] Sierra Club/100, Burgess/31.
[51] Sierra Club/100, Burgess/35.
[52] Sierra Club/100, Burgess/44.

Q. Sierra Club claims that the Company's Initial Filing did not include any analysis supporting the estimated costs for coal supplied by the Black Butte mine in 2023.[53] How do you respond?

A. The estimates included in the Company's Initial Filing are no longer relevant because they have been supplanted by the actual terms and conditions of the executed CSA. That said, the Company's Initial Filing included estimated Black Butte costs because the CSA had yet to be finalized. This approach was consistent with prior TAMs, including the 2022 TAM.[54] The estimated costs for 2023 were based on indicative pricing received from Black Butte in December of 2020 and were escalated based on changing market conditions. This information was included in the workpaper labeled "BRIDGER FLLT 2023 TAM DF Cycling.xlsx".

Q. What was the basis for the estimated 2023 volumes from Black Butte?

A. The delivery volumes from Black Butte assumed in the 2023 TAM are a function of the generation forecast results from the Aurora model and the deliveries available from BCC. Generation volumes at power plants vary year to year based upon many variables including PacifiCorp's transmission system, power and natural gas prices, new or retired system resources, etc.

Q. Why did the Company's Initial Filing assume that the new Black Butte CSA would include a minimum take obligation?

A. Nearly all coal supply contracts have minimum purchase obligations and assuming no minimum take for the new Black Butte CSA would have been unreasonable. Again, this approach is consistent with prior TAMs, including the 2022 TAM where Sierra

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[53] Sierra Club/100, Burgess/32.
[54] *See, e.g.,* Order No. 21-379 at 11.

Club objected to the Company's assumption that it would be subject to minimum take obligations for contracts that had yet to be signed, including the Black Butte CSA.[55] The Commission rejected Sierra Club's argument in the 2022 TAM and should do so here.

Q. How do the Black Butte estimated minimum take volumes in the Initial Filing compare to those currently in rates?

A. For Black Butte the 2023 TAM Initial Filing included an estimated minimum take quantity of [redacted] tons, compared to [redacted] tons in the 2022 TAM.

Q. Sierra Club claims that the Company did not explore any alternative to purchasing [redacted] tons from Black Butte in 2023.[56] Is this true?

A. No. In late 2020, PacifiCorp solicited indicative pricing and volumes from the Black Butte mine associated with a potential contract beginning in 2022. Black Butte provided a range of volume options with several different indicative prices. The Company evaluated several options together with Idaho Power, the joint owner of the Jim Bridger plant. Additionally, in 2022, an analysis to determine whether to execute a new contract with Black Butte was performed by the Company's resource planning group. As explained above, that analysis is attached as Highly Confidential Exhibit PAC/801.

Q. Sierra Club claims that the Black Butte cost was not properly evaluated because it was not included in the Aurora dispatch model for the TAM.[57] Is this true?

A. No. First, Black Butte costs were not included in dispatch because only the contract

[55] Order No. 21-379 at 11.
[56] Sierra Club/100, Burgess/34.
[57] Sierra Club/100, Burgess/34.

minimum was included in the TAM, with no incremental coal available. Second, Sierra Club is conflating the review process for executing a new CSA with the process for estimating costs for the TAM filing.

Q. Sierra Club claims that the results of the No Minimum Scenario run modeled after the 2021 IRP indicate that the Company does not need to purchase any coal from Black Butte in 2023 because, according to Sierra Club, "PacifiCorp demonstrated that the Jim Bridger plant could operate through 2037, while maintaining grid reliability, even without the 'required' quantity fuel of that [sic] Black Butte would supply."[58] Is this true?

A. No. As discussed in detail above, the No Minimum Scenario is not realistic or practical. The scenario where the Company shutters BCC in 2025 and relies exclusively on stockpiled coal is also entirely unrealistic and would lead to the early retirement of the Jim Bridger plant, which is contrary to the Company's acknowledged 2021 IRP, and would therefore not benefit customers.

Q. Sierra Club also points to the stockpile at Bridger and claims that it could be used if demand is higher than expected, which further obviates the need for Black Butte coal.[59] Is that true?

A. No. The TAM Aurora model generation results demonstrate that there is a need for coal from Black Butte. Without deliveries from Black Butte in 2023, the coal stockpile would be exhausted before the end of the year.

[58] Sierra Club/100, Burgess/35.
[59] Sierra Club/100, Burgess/35.

Q. Sierra Club claims that the Company "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)."[60] Do you agree?

A. No. Sierra Club fails to recognize the many differences between a multi-year CSA with a third-party and an annual mine plan prepared by an affiliate mine. These differences include the length of time covered, the added flexibility over long-term production provided by ownership of the mine, and impacts of market-based pricing from third parties versus cost-based pricing from an affiliate. While PacifiCorp agrees that an annual mine plan can inform the review of the reasonableness of the fuel costs from an affiliate mine, PacifiCorp disagrees that the same standard for review of a multi-year CSA should apply to an affiliate mine plan.

Q. Sierra Club claims that the 2023 BCC mine plan provided in discovery included insufficient details and the Company indicated that the mine plan will not be finalized until the fourth quarter of this year, well after this proceeding has ended.[61] How do you respond?

A. All BCC workpapers were provided as part of the Initial Filing. The TAM uses a forecast rate year and inherently must include estimates. Furthermore, critical outputs of a mine plan include coal production volumes, coal quality, operating costs and capital expenditures. The 2023 BCC mine plan provided sufficient detail for all of these outputs.

[60] Sierra Club/100, Burgess/36.
[61] Sierra Club/100, Burgess/36.

Q. Please explain BCC's typical annual mine plan process.

A. On an annual basis for operational planning, BCC reviews the optimum approach to meeting BCC's portion of the fuel needs at the Jim Bridger plant and forecasts the associated costs. Mine plans consider operational, geologic, and safety considerations that affect the amount of coal that can or must be mined in a given year to maintain the appropriate level of production. BCC develops several mine plan alternatives with varying levels of production, and then PacifiCorp and Idaho Power select the mine plan that is least cost, risk adjusted, and best fits the forecasted generation at the Jim Bridger plant for the following calendar year. The selected mine plan dictates how the mine is operated, informs dispatch and budgeting decisions, and is reflected in net power cost filings such as the TAM. Mine plans are generally prepared during the summer months for the following calendar year.

Q. Does BCC have mine plans that are longer than one year?

A. The term 'mine plan' can be used to describe planned mining activities that range from an annual mine production plan, to planning that aligns with the Company's 10-year business plan, to plans for all mining activities necessary to complete final reclamation. BCC's annual mine plan is the most critical because of its impacts to dispatch and budget decisions, which is why it is revisited and prepared each year.

Q. Can PacifiCorp realize cost savings by reducing production from the levels set in the annual mine plan?

A. No. BCC cannot reduce Jim Bridger's overall costs per unit by producing less coal than forecast in a particular year because over the short term (i.e. the TAM planning period), coal production costs include fixed costs that are unavoidable. Since these unavoidable fixed costs have the same effect on fuel costs as minimum take obligations, BCC's fixed costs and corresponding minimum mine production levels are treated the same way as minimum take obligations for analysis purposes. BCC does, however, have some ability to flex its supply upward to meet additional generation requirements at the Jim Bridger plant. As just explained, BCC typically develops costs for different mine plans to identify expected coal costs at differing targeted production levels. The cost differential between the plans is divided by the tonnage differential between the plans to determine BCC's expected incremental cost for any supplemental coal supplies.

Q. Sierra Club claims that significantly reducing Jim Bridger's output could reduce NPC.[62] Is that true?

A. No. Sierra Club has unsuccessfully made some version of this argument in the last two TAMs. As in previous cases, Sierra Club points to modeling runs that show benefits from reducing generation at the Jim Bridger plant—but only by leaving out costs that must be accounted for. As an example, Sierra Club fails to recognize that there is a minimum prudent operating level at BCC. Operating below this level would result in foregoing lower-cost incremental coal, would reduce customer benefits from the BCC investment, and would still require labor costs at the minimum prudent operating level in order to preserve the skilled workforce necessary to comply with statutory final reclamation requirements. Company witness Mitchell specifically addresses the problems associated with the model runs upon which Sierra Club relies and demonstrates that current output at the Jim Bridger plant reduces NPCs.

[62] Sierra Club Direct Testimony, 25:9-35:10.

Removing the Jim Bridger plant from the 2023 TAM or reducing its production would both increase costs for customers and reduce reliability.

Q. Sierra Club faults the Company for not examining the potential cost of significantly reduced BCC production.[63] How do you respond?

A. As discussed above, the 2022 Fuel Plan indicates that as BCC production decreases, NPC increases, which undermines Sierra Club's argument that lower BCC production decreases costs.

Q. Sierra Club claims that the Company is imprudent because it has not considered significantly reduced BCC production in the TAM because the TAM is a one-year look at BCC operations but claims that "PacifiCorp willfully avoids any long-term fuel planning considerations at BCC which could benefit its customers."[64] How do you respond?

A. In that statement, Sierra Club's testimony disingenuously ignores the 2022 Fuel Plan, which is precisely the long-term planning analysis Sierra Club claims that the Company "willfully avoids." Furthermore, although the Company does not publish a long-term fuel plan report every year, the Company does conduct long-term mine planning and long-term fuel planning every single year as part of its 10-year business planning process. As discussed above, the Company intends to update the 2022 Fuel Plan every two years in alignment with the Company's IRP process to provide precisely the analysis Sierra Club is looking for.

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[63] Sierra Club/100, Burgess/37.
[64] Sierra Club/100, Burgess/37-38.

Q. Sierra Club argues that the Company has admitted that it "can still meaningfully adjust some of its costs (e.g., labor) within a one-year time horizon," which Sierra Club claims contrasts with prior TAMs where the Company argued labor costs "were entirely fixed."[65] Is this true?

A. The data response referenced by the Sierra Club actually states "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." The Company has repeatedly stated that certain costs, like labor, could be treated as fixed depending on the time frame those costs are considered. Regardless, the BCC production level in the 2023 TAM aligns with the generation forecast as provided by the TAM Aurora model results. In addition, the Company reiterates that it is important for BCC to maintain a workforce with the core skills required to respond to future potential coal demand increases and complete reclamation as required by federal and state regulations.

Q. Sierra Club concedes that the Company did evaluate different production scenarios for BCC in 2023 but claims that the Company has not explained how it selected the production level used in the 2023 TAM.[66] How do you respond?

A. PacifiCorp provided detailed information about the 14 different mine plans considered for the TAM and the assessment results that determined the scenario selected in the response to Sierra Club Data Request 2.9. Sierra Club claims that Table 4 in their testimony reflects the information provided by the Company in this

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[65] Sierra Club/100, Burgess/38.
[66] Sierra Club/100, Burgess/39.

data request, however, they omit the narrative explanations provided for each of the mine plans considered.[67] Sierra Club claims that the Company could have selected a lower production level and then replaced Jim Bridger generation with other resources. However, what Sierra Club fails to recognize is the Aurora model already selects the lowest cost options for generation, which included a higher level of coal production from BCC. Any alternative resource selected would have been a higher cost option.

Q. Sierra Club claims that the BCC production levels in the 2023 TAM differ from the 2023 production levels in the 2022 Fuel Plan.[68] Is that true?

A. Yes. However, the base mine plan used for the 2023 TAM is the same as the base mine plan for Scenario 4 of the 2022 Fuel Plan. The difference between the two plans is in the volume of supplemental tons delivered based on changes to the generation forecast and the sourcing mix of BCC and Black Butte coal. The 2023 TAM Initial Filing was prepared in February 2022, and the mining plans used for the different 2022 Fuel Plan scenarios were created and/or updated in March 2022. Sierra Club seems to take exception with the use of different mine plans in the TAM and in the 2022 Fuel Plan, but the purpose of the 2022 Fuel Plan is to assess different scenarios for long-term coal supply at the Jim Bridger plant. In addition, it is worth noting that mine plans are developed and then refined as necessary over the course of the annual planning cycle to support the Company's business planning requirements.

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[67] Sierra Club/100, Burgess/39-40.
[68] Sierra Club/100, Burgess/40-41.

Q. Sierra Club claims that BCC could produce as little as [redacted] base tons (or 0.8 million base tons on a PacifiCorp-basis) but that PacifiCorp never studied a scenario, either in the 2023 TAM or the 2022 Fuel Plan, that assumed as low as [redacted] base tons.[69] Is that true?

A. No. The [redacted] tons cited by Sierra Club in the 2022 Fuel Plan represents an average of the BCC low production scenario and includes a year that transitions to highwall mining. For Sierra Club to take this average value and apply it to a year that has no highwall mining would not be appropriate. Furthermore, as discussed in the response to Sierra Club Data Request 2.9, the Company evaluated several BCC mine plan options while developing the 2023 TAM. In the 2023 TAM, the Company prudently selected a BCC medium production plan that when combined with BCC incremental coal and coal sourced from Black Butte, provided a balanced and economic fuel supply to meet the generation forecast modeled in Aurora. In the 2022 Fuel Plan, the Company evaluated multiple BCC mine plan scenarios. The [redacted].

Q. Sierra Club claims that PacifiCorp "might be concealing information about its planning and analysis related to the BCC mine plan."[70] How do you respond?

A. The Company strongly disagrees with any suggestion that it is intentionally concealing information. In this case alone, the Company has responded to over 90 discovery requests from Sierra Club related almost exclusively to coal costs in general and overwhelmingly related to the Jim Bridger plant. The literally hundreds

[69] Sierra Club/100, Burgess/24-25, 41.
[70] Sierra Club/100, Burgess/42.

of pages of analysis provided to Sierra Club hardly constitutes concealment of information.

In Sierra Club's testimony they refer to two 2022 California Energy Cost Adjustment Clause (ECAC) data requests that they claim contradict each other. PacifiCorp explained in ECAC rebuttal testimony how Sierra Club misinterpreted the responses[71], but in their TAM testimony Sierra Club ignores the clarification provided and continues to misinterpret the responses.

Q. Sierra Club faults the Company for not presenting the 2023 BCC mine plan to the Commission for approval because Sierra Club likens BCC's annual mine plans to CSAs.[72] How do you respond?

A. There are many differences between a multi-year CSA with a third-party and an annual mine plan prepared by an affiliate mine. First, the mine plan does not represent a long-term commitment to buy coal at a certain cost such as a CSA does. Second, the mine has greater production flexibility over the long-term due to the ownership of the mine. Third, a CSA contains market-based pricing from third parties versus cost-based pricing from an affiliate mine. While PacifiCorp agrees that an annual mine plan can inform the review of the reasonableness of the fuel costs from an affiliate mine, PacifiCorp disagrees that the same standard for review of a multi-year CSA should apply to an affiliate mine plan.

[71] 2022 California ECAC, PAC/800, Owen/17:20-18:4.
[72] Sierra Club/100, Burgess/43.

Q. Sierra Club claims that the Company has a disincentive to reduce BCC production even if doing so is lower cost.[73] Is this true?

A. No. PacifiCorp's planning processes are specifically designed to determine the least cost, risk-adjusted level of production from BCC. PacifiCorp's interests are best served by operating BCC in the most cost-effective manner possible, which aligns with its customers' interest in maintaining low-cost, reliable service. Sierra Club's allegations to the contrary are speculative and devoid of any evidentiary support.

Q. Sierra Club argues that PacifiCorp has not evaluated how to reduce costs at the Jim Bridger plant or acted to do so.[74] Is this true?

A. No. BCC's annual mine plans and Jim Bridger's long-term fuel plans are designed to determine the least cost, risk-adjusted fuel supply for the plant and work to keep the Jim Bridger plant's fuel costs as low as possible. In addition, PacifiCorp actively engages in comprehensive cost-management and oversight of BCC's operations. PacifiCorp works closely with BCC personnel to ensure the mine operates safely and production and cost targets are achieved. For example, PacifiCorp: (1) coordinates daily calls between BCC, PacifiCorp fuel resources employees, Idaho Power, and Jim Bridger plant employees to inform coal delivery and quality requirements and minimize coal handling activities (daily, weekly, monthly, and annual targets discussed); (2) reviews daily production cost reports to measure performance on a real-time basis; (3) reviews monthly performance reports to ensure targets are achieved and areas requiring course correction are identified; (4) includes BCC in corporate alliances to achieve greater volume discounts where applicable; (5) requires

[73] Sierra Club/100, Burgess/43.
[74] Sierra Club Direct Testimony, 35:22-24, 37:9-14.

PacifiCorp approval prior to hiring new employees; (6) requires evaluations and approvals for capital expenditures; and (7) attends Management Committee Meetings with Idaho Power and BCC representatives on a quarterly basis to evaluate and direct mine activities.

Q. Sierra Club recommends that, "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."[75] Is this a reasonable recommendation?

A. No. Sierra Club's recommendation effectively asks the Company to file an updated long-term fuel plan with each TAM, which is unreasonable for the reasons discussed above.

C. Average Cost Dispatch

Q. Sierra Club claims that PacifiCorp could reduce Jim Bridger generation by using average price dispatch and that doing so would also reduce overall NPC.[76]

A. Company witness Mitchell's testimony addresses the fundamental basis for the Company's use of incremental, rather than average, price dispatch. My testimony explains why Sierra Club's reliance on average price dispatch improperly ignores fixed costs and minimum take volumes at BCC that, when properly accounted for, increase NPC.

[75] Sierra Club/100, Burgess/44.
[76] Sierra Club/100, Burgess/47.

Q. Sierra Club claims that in the average price model run, PacifiCorp improperly included [redacted] in Jim Bridger plant fixed costs.[77] Please explain what those costs represent and why they are appropriately treated as fixed costs.

A. In the average price model run the average prices are calculated based on assumed minimum volumes from BCC and from Black Butte. If the generation results in the average price model are lower than these minimum volumes the Company still needs to account for the associated minimum cost obligations for the minimum volumes. Ignoring these costs would suggest that the Company could obtain coal at any volume with no consideration for the upfront costs needed to produce the coal at BCC or the guarantees required by a third-party to supply coal through a CSA, which is not realistic in actual operations.

Q. Sierra Club claims that when the Company filed its application in this case "there were little to no costs that were predetermined for 2023" because there was no Black Butte contract for 2023 (and therefore no minimum take amount) and the Company can reduce BCC production thereby avoiding otherwise fixed costs associated with higher production volumes.[78] How do you respond?

A. If the Company were to implement Sierra Club's recommended approach to reduce BCC production and essentially eliminate coal supplied by Black Butte (since Black Butte did not provide indicative pricing without a minimum obligation), then the lost Jim Bridger generation would need to be replaced by a higher-cost resource and would harm customers.

[77] Sierra Club/100, Burgess/48.
[78] Sierra Club/100, Burgess/49.

Q. When the fixed costs are appropriately accounted for, does using average price dispatch reduce NPC?

A. No.

Q. Sierra Club also points to the No Minimum Scenario run modeled after the 2021 IRP, which it claims demonstrates that using average cost dispatch would significantly reduce generation at the Jim Bridger plant and lower overall NPC.[79] Would that scenario actually produce lower system costs?

A. No. As the Company explained in the 2021 IRP proceeding in Oregon docket LC 77, the No Minimum Scenario assumed that there were no contractual obligations of any kind for future fueling beyond current contracts. To operate Jim Bridger without fueling contracts, however, would require that adequate and reliable coal supply is available on demand. The only feasible way for that to occur would be for the Jim Bridger plant to procure coal from the SPRB, which would require a significant capital investment to retrofit the plant for the safe delivery and handling of large volumes of SPRB coal to replace the existing coal supply, as discussed in the 2022 Fuel Plan. When the capital costs of SPRB coal are included, the No Minimum Scenario was higher cost than alternatives, which demonstrates that it does not indicate that NPC can be reduced by using average cost dispatch.

[79] Sierra Club/100, Burgess/50-51.

Q. Sierra Club disputes the Company's claim that it would be required to retrofit Jim Bridger plant to accept SPRB coal under the No Minimum Scenario because there are several scenarios in the 2022 Fuel Plan that do not include the SPRB investment.[80] How do you respond?

A. Sierra Club effectively assumes that the Company could procure any volume of coal on demand either at BCC or from Black Butte. This assumption is entirely unrealistic. Moreover, the 2022 Fuel Plan scenarios that avoid the retrofits required to accept large volumes of SPRB coal are the scenarios that assume ongoing contractual obligations to purchase coal and produce coal at BCC, both of which includes unavoidable costs that are not included in the No Minimum Scenario.

Q. Sierra Club also claims that the Jim Bridger plant only needs about [redacted] tons of coal in total through 2037 and it could mine that amount in the next [redacted] years.[81] Is this true?

A. No. Sierra Club's claim is based on the assumption that the 2021 IRP No Minimum Scenario is the preferred scenario for the Jim Bridger plant. As stated above, this scenario ignores costs that are unavoidable in actual operations, among other impracticalities. When these costs are included, the No Minimum Scenario is a higher-cost option than alternatives. These alternative scenarios require higher levels of coal production to meet the generation requirements at the Jim Bridger plant.

[80] Sierra Club/100, Burgess/52.
[81] Sierra Club/100, Burgess/52.

D. Naughton Coal Costs

Q. Sierra Club is concerned that the [redacted].[82] Why does the CSA have [redacted]?

A. The terms of the Naughton CSA are a negotiated outcome. Contract terms are negotiated in a way that is acceptable to both parties, thus in order for the Company to achieve terms it prefers, it must also account for terms preferred by the counterparty. Without this practice, contracting would not be possible.

It is common for business contract terms to include pricing adjustments to reduce the inflation risks to the supplier. The fact that this contract has an [redacted]

Q. Sierra Club recommends that [redacted], the Commission should evaluate whether any increased costs could have reasonably been avoided through alternatives.[83] How do you respond?

A. The Company was able to negotiate [redacted] that represent greater benefits for customers. Sierra Club's recommendation that the Commission review the prudence of the contract again in the future [redacted] would represent improper hindsight review and would be contrary to the Commission's prudence standard.

[82] Sierra Club/100, Burgess/61.
[83] Sierra Club/100, Burgess/61.

Q. Sierra Club also recommends that future TAM filings include greater transparency into the scenarios that the Company intends to use to evaluate new CSAs.[84] How do you respond?

A. First, Sierra Club's recommendation is fundamentally the same as its recommendation in the 2022 TAM that the Commission adopt guidelines applicable to future CSA reviews. The Commission rejected Sierra Club's recommendation in the 2022 TAM and should do so here too.[85] Second, to the extent that Sierra Club's recommendation would introduce a pre-approval process for CSA terms, such an approach is contrary to established regulatory precedent where the Company is obligated to operate in a prudent manner and the Commission then subsequently reviews the prudence of those actions.

E. Huntington Coal Costs

Q. Sierra Club faults the Company's analysis of the costs and benefits of exercising the termination clause in its Huntington CSA because it did not include production cost modeling and an IRP-type analysis using the PLEXOS model.[86] How do you respond?

A. Sierra Club's criticism is unwarranted, as discussed in more detail in Company witness Seth Schwartz's testimony.

Q. Does this conclude your reply testimony?

A. Yes.

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[84] Sierra Club/100, Burgess/61.
[85] Order No. 21-379 at 7.
[86] Sierra Club/100, Burgess/62.

REDACTED
Docket No. UE 400
Exhibit PAC/801
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of James Owen

Black Butte Coal Supply Agreement Analysis

June 2022

THIS EXHIBIT IS HIGHLY CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 400
Exhibit PAC/900
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Seth Schwartz

June 2022

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ATTACHED EXHIBITS

I. IDENTIFICATION OF WITNESS AND QUALIFICATIONS

Q. Please state your name, business address, and present position.

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209. My position is Managing Director, Energy Ventures Analysis, Inc. (EVA).

Q. On whose behalf are you submitting reply testimony?

A. I am an independent expert PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) has retained to testify on one of the issues raised in this case, the analysis of the costs and benefits if the Company were to exercise the Environmental Review clause in the Huntington Coal Supply Agreement (CSA).

Q. Describe your education and professional experience.

A. I am the Managing Director of EVA and have been a principal since its founding in 1981. EVA performs market analysis and management consulting for the United States (U.S.) energy markets. We cover markets for coal, natural gas, oil and electric power. Our clients are participants in the energy market, including producers, consumers, transporters, investors, and regulators. In addition to my corporate responsibilities, I manage our coal consulting practice, including market studies, publications, and management consulting. Our market studies include analyses of coal supply, demand, and prices. Our consulting projects include management audits of fuel procurement practices by electric power companies, both regulated and unregulated. Our management audits have included projects for regulatory agencies, interveners, and company management. I have testified as an expert witness on energy markets and fuel procurement practices in front of numerous state public utility commissions as well as the Federal Energy Regulatory Commission (FERC). My current resume is attached as Exhibit PAC/901. I have a Bachelor of Science in Geological Engineering degree from Princeton University.

Q. Have you testified in previous regulatory proceedings?

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

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

A. Yes. In 1991, following the merger of Utah Power & Light and PacifiCorp, I directed a study of the coal supply operations and fuel procurement practices of PacifiCorp on behalf of the seven state[1] public service commissions and FERC, as well as a subsequent update in 1995. These studies were comprehensive reviews of the management of the mining operations and coal supply plan for all of PacifiCorp's coal-fired generation facilities. In 2011, I also testified on behalf of the Utah Office of Consumer Services in Docket No. 10-035-124 regarding PacifiCorp's fuel supply management and coal supply operations. I have also testified on behalf of PacifiCorp in the states of Oregon, California, Idaho, Utah, Washington, and Wyoming.

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

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

A. In 2015, I filed testimony on behalf of PacifiCorp in docket UM 1712. In 2017, I filed testimony on behalf of PacifiCorp in docket UE 323. In 2020, I filed testimony on behalf of PacifiCorp in docket UE 375. In 2021, I filed testimony on behalf of PacifiCorp in docket UE 390.

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

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

Q. Did any parties to docket UM 1712 question the prudence of the Company entering into a long-term CSA for the Huntington Plant?

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

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

A. The subject of my testimony was regarding the structure of coal markets in the U.S. in general and for PacifiCorp's power plants in particular, the role of multi-year coal contracts in supplying reliable and economic fuel for plant operations, and the function of take-or-pay and liquidated damage provisions in long-term coal supply contracts.

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

A. Yes. Testimony was filed by Commission Staff and Sierra Club raising various issues related to PacifiCorp's CSAs and coal procurement strategies. Staff proposed specific adjustments related to economic cycling of coal plants and liquidated damages under the Cholla CSA, while Sierra Club proposed a specific adjustment related to the Naughton plant. The Company's plan to enter a new contract to supply the Jim Bridger plant with Black Butte Coal Company to replace an expiring contract was also at issue. The CSAs reviewed in the case contained minimum take provisions.

Q. What was the subject of your 2020 testimony in docket UE 375?

A. The subject of my testimony was regarding the structure of coal markets in the U.S. in general and for PacifiCorp's power plants in particular, the need for multi-year coal contracts in supplying reliable and economic fuel for plant operations, the need for minimum-volume commitments in coal supply contracts, and the purpose of take-or-pay and liquidated damage provisions. Also, I testified as to standard utility practice in using incremental cost of generation in dispatching power plants rather than the average cost.

Q. What was the subject of your 2021 testimony in docket UE 390?

A. The subject of my testimony was the need for electric power companies to purchase coal under long-term supply contracts with minimum take provisions to assure an adequate supply of coal to meet power plant burn requirements. I also testified to the prudence of the Company's decisions to sign long-term CSAs for the Huntington and Hunter power plants.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the Commission Staff testimony of Steve Storm as well as the testimony of Ed Burgess, filed on behalf of Sierra Club, challenging the adequacy of the report I prepared in response to the directive of the Commission analyzing the costs and benefits if the Company were [redacted].

Q. Please summarize your testimony.

A. My testimony:

- Summarizes the analysis of the costs and benefits of [redacted];
- Responds to the criticisms from Staff that the "Huntington Analysis is not a thorough explanation of the costs and benefits of contract termination or renegotiation"; and,
- Responds to the criticisms from Sierra Club that the analysis of early termination of the Huntington CSA is limited because it did not include production cost modeling.

III. THE COSTS AND BENEFITS OF "EARLY TERMINATION" OF THE HUNTINGTON CSA

Q. What was the scope of the report you prepared regarding the [redacted] in the Huntington CSA?

A. The Commission directed the Company to prepare an analysis of the costs and benefits of [redacted] in the Huntington CSA. The Company retained my company, EVA, to prepare this analysis and a report, which was filed by the Company (the "Huntington Report"). The analysis focused on whether the Company would [redacted].

Q. Did the Huntington Report include an [redacted]?

A. Yes. If the Company [redacted]

Q. Staff "take(s) issue with the assumption of the singular exercise date of January 1, 2022." Why did you choose that exercise date for your analysis?

A. The costs and benefits of the [redacted]. The Company could [redacted] during the review period for the current transition adjustment mechanism (TAM). The only date that would be relevant for this analysis is a date during the review period. I selected January 1, 2022, as the appropriate date during this period as a date that is a representative date for the Company to consider in its analysis.

Q. Staff suggested that the analysis should consider an exercise date in the future, such as January 1, 2028. Why did you not consider a future exercise date?

A. The state of future energy markets (including power and coal markets) is highly uncertain. There is no way to evaluate the [redacted] at some future date with any certainty. There is no value to the Company in [redacted] in the future based on projected energy markets. The Company has time to consider future markets, as well as the impact of future environmental laws, rules, or regulations, in the future and make a decision [redacted] based on the facts known at that time.

Q. Would it make any sense for the Company to consider [redacted] on January 1, 2028, as suggested by Staff?

A. No.

Q. Why not?

A. [redacted]

Q. Staff also concluded that the analysis "was less than thorough in the consideration of joint coal supply between the Hunter and Huntington plants. Is that true?

A. No. The Huntington Report had an extensive analysis of the coordination of the coal supply to the Hunter and Huntington power plants. [redacted]

Q. If the Company were [redacted], could it supply the Huntington plant with coal purchased under the existing coal supply contracts currently supplying the Hunter plant?

A. No. [redacted]. The Company could not substitute other coal for the Huntington plant, [redacted] Based on current and currently-expected coal market conditions, the cost of new coal supply after the end of the Interim Period [redacted]

Q. Could the Company develop a strategy to purchase coal for both the Hunter and Huntington plants after the end of the Interim Period and the termination of the Huntington CSA?

A. Yes. The Company does consider its coal supply options for both the Hunter and Huntington plants as these plants can both use similar coal produced in Utah.

Q. Did the Huntington Report consider [redacted]

A. [redacted]

Q. What did the Huntington Report conclude?

A. The Huntington Report concluded [redacted]

- [redacted]
- [redacted]
- [redacted]

Q. Does the Huntington Report conclude [redacted]

A. No. [redacted]

Q. Is the Huntington CSA currently providing economic benefits to the Company during the review period for the TAM?

A. Yes. The coal and electric power markets have been experiencing significant disruptions beginning in mid-2021 and extending through 2022. Because of changes in domestic and world energy markets, the prices of electric power, coal, and natural gas are extremely high in the western energy markets. The availability of coal is limited and the prices are high because of increased demand in both export markets and domestic power markets. Natural gas prices have risen to extremely high levels due to high demand for liquid natural gas exports and shortages of domestic supply. Power market prices are very high because of retirements of existing fossil fuel capacity, low hydroelectric power supply, and high fuel prices. The Company's coal supply contracting under the Huntington CSA (and its other long-term contracts) provides the ability to increase coal purchases at low coal prices to support increased generation and provide both reliability and low costs for its customers. The Huntington CSA makes it possible for the coal supplier to maintain the production capacity to support the plant generation and avoid the supply shortages being experienced by other power companies in 2022.

Q. Is it possible that the Company will face periods of time [redacted]?

A. Yes. There may be times [redacted] That is not happening during the review period for the TAM, but it may happen in the future. If it does, the Company will consider all of its options, [redacted] This provision makes it possible for the coal supplier to invest in the production capacity to support reliable generation at the Huntington plant.

Q. Should the Company consider the terms of the Huntington CSA in its integrated resource plan process, including the potential exercise of the ER Clause?

A. Yes. However, this is addressed in more detail by Company witness Daniel J. MacNeil.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 400
Exhibit PAC/901
Witness: Seth Schwartz

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Seth Schwartz

Seth Schwartz' Resume

June 2022

RESUME OF
SETH SCHWARTZ

EDUCATIONAL BACKGROUND

B.S.E. Geological Engineering, Princeton University, 1977

PROFESSIONAL EXPERIENCE

Current Position

Seth Schwartz is the President and co-founder of Energy Ventures Analysis. Mr. Schwartz directs EVA's coal and power practice and manages the COALCAST Report Service. The types of projects in which he is involved are described below:

Fuel Procurement
Assists utilities, industries and independent power producers in developing fuel procurement strategies, analyzing coal and gas markets, and in negotiating long-term fuel contracts.

Fuel Procurement Audits
Audits utility fuel procurement practices, system dispatch, and off-system sales on behalf of all three sides of the regulatory triangle, i.e., public utility commissions, rate case intervenors, and utility management.

Coal Analyses
Directs EVA analyses of coal supply and demand, including studies of utility, industrial, export, and metallurgical markets and evaluations of coal production, productivity and mining costs.

Natural Gas Analyses
Evaluates natural gas markets, especially in the utility and industrial sectors, and analyzes gas supply and transportation by pipeline companies.

Expert Testimony
Testifies in fuel contract disputes and rate cases, including arbitration, litigation and regulatory proceedings, regarding prevailing market prices, industry practice in the use of contract terms and conditions, market conditions surrounding the initial contracts, and damages resulting from contract breach.

Acquisitions and Divestitures
Assists companies in acquisitions and sales of reserves and producing properties, both in consulting and brokering activities. Prepares independent assessments of property values for financing institutions.

Prior Experience

Before founding Energy Ventures Analysis, Mr. Schwartz was a Project Manager at Energy and Environmental Analysis, Inc. Mr. Schwartz directed several sizable quick-response support contracts for the Department of Energy and the Environmental Protection Agency. These included environmental and financial analyses for DOE's Coal Loan Guarantee Program, analyses of air pollution control costs for electric utilities for EPA's Office of Environmental Engineering and Technology, Energy Processes Division, and technical and economic analysis of coal production and consumptions for DOE's Advanced Environmental Control Technology Program.

Publications

Crerar, D.A., Susak, N.J., Borcsik, M., and Schwartz, S., "Solubility of the Buffer Assemblage Pyrite + Pyrrhotite + Magnetite in NaCl Solutions from 200^{o} to 350^{o}", Geochimica et Cosmochimica Acta (42)1427-1437, 1978.

Docket No. UE 400
Exhibit PAC/1000
Witness: Zepure Shahumyan

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Zepure Shahumyan

June 2022

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Zepure Shahumyan. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. I am employed by PacifiCorp as the Director of Energy and Environmental Policy.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science in Biochemistry from Portland State University. I have been employed by PacifiCorp for over five years, initially as a net power cost (NPC) specialist, and for the last four years in Environmental Policy and Strategy functions. Prior to PacifiCorp, I worked for Bonneville Power Administration from 2010 in various positions of responsibility including enterprise risk management consulting and utility management strategy.

Q. Please explain your responsibilities as PacifiCorp's Director of Energy and Environmental Policy.

A. My current responsibilities include developing PacifiCorp's environmental policy, strategy, and programs as well as ensuring compliance for Company-wide renewable portfolio standards and reporting of greenhouse gas (GHG) emissions for California, Oregon, and Washington. I manage PacifiCorp's compliance with the California Air Resources Board Mandatory Reporting Regulation and Cap and Trade Program. Relevant to this proceeding, I manage PacifiCorp's implementation of Washington's

Clean Commitment Act (CCA), Senate Bill 5126, and future compliance activities under the Washington cap-and-invest program.[1]

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the CCA and PacifiCorp's compliance requirements under the program. I will address impacts from this law on Oregon customer rates, and how PacifiCorp has estimated the costs to comply with the law.

III. PACIFICORP'S WASHINGTON GHG OBLIGATION

Q. What is the CCA, and what is it trying to accomplish?

A. The CCA was signed into law by Washington Governor Inslee on May 17, 2021, and established a cap-and-invest program for the state that will be overseen and implemented by the Washington Department of Ecology. The CCA establishes regulatory requirements to reduce carbon emissions in the state.

Q. How does the CCA work?

A. The law attempts to reduce carbon emissions by establishing a market incentive for covered entities to reduce emissions. Generally speaking, the CCA accomplishes this by: (1) setting emissions targets (95 percent below 1990 levels by 2050); (2) establishing an annually decreasing "cap" on the amount of emissions that are permitted in the state (emissions are capped at 93 percent of 2023 baseline emissions, and generally decrease annually until 2050); (3) creating financial instruments for

[1] 2021 Wa. Laws Ch. 316 (available here: https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session%20Laws/Senate/5126-S2.SL.pdf?cite=2021%20c%20316%20%C2%A7%201).

permitted emissions, or “allowed” emissions that fall under the “cap;” and (4) establishing a market for entities to buy, sell, and trade allowances associated with permitted CCA emissions to comply with the emissions limits.

As the emissions cap decreases, the available allowances will decrease, and covered entities will either have to reduce emissions, secure extra allowances, or pursue alternative compliance options.

Q. When will this law go into effect, and what entities are obligated to comply?

A. Starting January 1, 2023, the CCA will apply to industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual greenhouse gas emissions above 25,000 metric tons of carbon dioxide equivalent.[2] The CCA applies to PacifiCorp because it is an in-state electricity generator and electricity importer.

V. IMPACT ON OREGON RATES

Q. Does PacifiCorp’s obligation for its Washington retail sales have any impact on customer retail rates in Oregon?

A. No. The GHG obligation associated with PacifiCorp’s retail obligations is anticipated to be fully covered by no-cost carbon allowances allocated for Washington customers and will not be reflected in Oregon rates.

Q. Please explain PacifiCorp’s obligation with regard to wholesale transactions.

A. The CCA rules have not been finalized. However, PacifiCorp assumes that the Company’s GHG obligation associated with wholesale imports to Washington, such as those imported through the Energy Imbalance Market, will be recovered by wholesale

[2] *Id.* § 9(1)(a).

transaction cost adders. These costs may eventually impact system NPC, because the costs are an expense incurred when importing to or exporting from Washington. PacifiCorp is currently planning to track and manage both its wholesale energy and allowance transactions, consistent with least-risk, least-cost principles, once Washington begins conducting auctions and allowances are available to purchase.

Q. How does the GHG obligation from Chehalis impact the dispatch price and the costs of operating Chehalis?

A. The costs to purchase carbon allowances to cover the GHG obligation from Chehalis that are not covered by CCA allowances increase the costs for operating Chehalis and are thus incorporated into the dispatch price for Chehalis.

Q. When will the CCA establish a carbon allowance price?

A. The Washington Department of Ecology is expected to conduct the first CCA auction in the first quarter of 2023.[3] That auction and subsequent quarterly auctions will determine the prices for carbon allowances that PacifiCorp must procure to meet its GHG obligation under the CCA. The rulemaking does not provide guidance on the potential allowance price.

Q. How was the CCA allowance price estimated for the TAM?

A. The Company used the California Carbon Allowance forward Intercontinental Exchange settlement price of $30.45 per metric ton of carbon dioxide equivalent as the best approximation of the Washington carbon allowance price available in May 2022. Company Witness Ramon Mitchell describes in his testimony how this price was incorporated into the modeling for the NPC forecast.

[3] *CCA Rulemaking,* New Section WAC 173-446-300(1).

Q. Does this conclude your reply testimony?

A. Yes.