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Exh. TRB-1CTr
Docket UE-230172
Witness: Thomas R. Burns

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-230172

PACIFICORP

REDACTED DIRECT TESTIMONY OF THOMAS R. BURNS

March 2023 (REVISED April 4, 2023, and REFILED April 19, 2023)

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Thomas R. Burns, my business address is 825 NE Multnomah Street, Suite LCT 600, Portland, Oregon 97232. I am currently employed as Vice President of Resource Planning and Acquisitions for PacifiCorp.

Q. Please describe your education and professional experience.

A. I graduated from Illinois State University with a Bachelor of Science degree in Economics. I joined PacifiCorp in 2007 and assumed the responsibilities of my current position in September 2022. Over this period, I held several operational, analytical and leadership positions within the Company. My previous role with PacifiCorp was Director of Energy Supply Management, Operations, and Reliability. In that role I was instrumental in the design and implementation of the Western Energy Imbalance Market.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for aspects of PacifiCorp's resource planning and procurement functions, which include the integrated resource plan (IRP), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this general rate case, I oversee the planning, analysis, and outreach processes that are used to develop PacifiCorp's IRP, and the economic analysis that helps guide the Company's resource acquisitions.

II. PURPOSE OF TESTIMONY

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

A. I provide economic analysis that supports PacifiCorp's decisions to:

- Convert Jim Bridger Units 1 and 2 to natural gas operations;
- Acquire the 190-megawatt (MW) Rock Creek I, and 400 MW Rock Creek II wind facilities (together, Rock Creek Projects); and
- Acquire and repower the 43 MW Foote Creek II-IV and 49 MW Rock River I wind facilities in Wyoming (the Repowered Facilities).

I also summarize PacifiCorp's assessment of the projects from the 2021 IRP and IRP Update, the 2021 Clean Energy Implementation Plan (CEIP), and discuss customer benefits that result from these projects.

Q. Please provide an overview of your testimony on Jim Bridger Units 1 and 2.

A. As discussed below, my economic analyses indicate that converting Jim Bridger Units 1 and 2 to natural gas is in the public interest and will generate benefits for Washington customers. Compared to early retirement of Jim Bridger Units 1 and 2, natural gas conversion has a present-value revenue requirement differential (PVRR(d)) customer benefit ranging from \$271.68 million to \$656.41 million, The range of benefits depends on the timing and magnitude of early coal unit retirement assumptions.

These substantial customer benefits are expected because the conversion is anticipated to cost approximately \$20.8 million. While the assumed operational life of a new gas peaking asset is longer than the assumed life of Jim Bridger Units 1 and 2 once converted to gas-fueled generating units, the upfront capital required to convert to natural gas is significantly less than installing a new gas-fired generating unit. The Jim Bridger gas conversions represent a significant opportunity to maintain much needed system capacity at a very low cost, during a period when there are growing resource adequacy concerns throughout the region.

Q. Please provide an overview of your testimony for the Rock Creek Projects.

As discussed below, my economic analyses indicate that both projects are in the public interest and will generate benefits for Washington customers.

Before passage of the Inflation Reduction Act (IRA), customer benefits for the Rock Creek Projects ranged from $33 million when using medium natural gas and medium Carbon dioxide (CO_2) assumptions to $143 million for high natural gas and high CO_2 assumptions. When factoring in the IRA, these benefits increased to $185 million when using medium natural gas and medium CO_2 assumptions and $298 million for high natural gas and high CO_2 assumptions. Conservatively, these benefits do not assign any value to the renewable energy credits (RECs) that will be generated by the Rock Creek Projects that can be used for compliance with the Clean Energy Transformation Act (CETA), providing additional customer benefits.

Q. Please provide an overview of your testimony for the Repowered Facilities.

A. As discussed below, my economic analyses indicate that both projects are in the public interest and will generate benefits for Washington customers.

Before passage of the IRA, customer benefits for Foote Creek II-IV ranged from $53.07 million when using medium natural gas and medium CO_2 assumptions to $80.8 million for high natural gas and high CO_2 assumptions. When factoring in the IRA, these benefits increased to $76.49 million when using medium natural gas and medium CO_2 assumptions and $104.23 million for high natural gas and high CO_2 assumptions. For Rock River I, customer benefits range from $30.15 million when using medium natural gas and medium CO_2 assumptions to $67.76 million for high natural gas and high CO_2 assumptions before adjusting for the IRA. When factoring in the IRA, these benefits increased to $54.09 million when using medium natural gas and medium CO_2 assumptions and $91.69 million for high natural gas and high CO_2 assumptions.

Conservatively, these benefits do not assign any value to the RECs that will be generated by the Repowered Facilities, which can be used for compliance with CETA, providing additional customer benefits.

III. JIM BRIDGER UNITS 1 AND 2 NATURAL GAS CONVERSION

Q. Please describe the conversion of Jim Bridger Units 1 and 2 to natural gas.

A. As described in the testimony of Company witness Brad D. Richards, Exhibit No. BDR-1T, PacifiCorp is converting the Company's coal-fired Jim Bridger Units 1 and 2, located near Point of Rocks, Wyoming, to run on natural gas. The units are expected to be offline by January 2024, and converted to natural gas and in service by May 2024. Consistent with the Company's 2021 IRP, the Company assumes the converted Jim Bridger Units 1 and 2 will serve Washington customers until the end of 2029, and serve PacifiCorp's other service territories through 2037.

A. <u>Need</u>

Q. Please provide an overview of the Company's IRP process.

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk to develop the Company's plans to provide reliable and reasonably priced service for its customers. The primary objective of the IRP is to identify the least-cost, least-risk portfolio of resources to serve customers in the future: this "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks.

The Company completes an IRP cycle every two years (odd-numbered years), which includes preparing a full IRP every two years and an update to the full IRP in the off years (even-numbered years). The Company submits both its IRP and IRP Update to each of the six regulatory commissions in the states where the Company provides retail service. Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process, which typically spans at least a full year before the release of a full IRP, PacifiCorp holds regular meetings with stakeholders to solicit feedback on the Company's planning assumptions, methodologies, and model results.

Q. Did the Company's 2021 IRP identify a need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of any IRP is to forecast the need for resources and evaluate different strategies to meet that need over time. The Company's 2021 IRP shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and increasing to over 6,600 MW by 2040. In 2025, the resource need in the 2021 IRP is 1,627 MW. As described further below, this need has increased since the 2021 IRP was finalized.

Q. How does the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflects a cost-conscious plan that includes near-term investments in renewable resources that can capture tax credits before they expire or decrease and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Can you describe the methodology that PacifiCorp used in the 2021 IRP to analyze the economics of its coal units and derive the preferred portfolio?

A. Yes. PacifiCorp incorporated a new and more advanced optimization modeling system called PLEXOS. The PLEXOS modeling system provides three platforms (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. Please refer to Company witness Rick T. Link's testimony for additional detail regarding PLEXOS and the LT, MT, and ST platforms.

Q. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[1]

[1] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022) (https://www.pacificorp.com/energy/integrated-resource-plan.html).

Q. What is the purpose of the 2021 IRP Update?

A. The IRP update is a checkpoint on the 2021 IRP action plan, and ensures that changes in the planning environment are considered between the two-year IRP planning cycle. The 2021 IRP Update assessed whether evolving trends and events impact customers and required changes to the action plan to deliver resources and transmission investments. Relevant here, the 2021 IRP Update reflects resource planning and procurement activities that occurred since the 2021 IRP, and present an updated load-and-resource balance and an updated resource portfolio.

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. As discussed in Company witness Link's testimony, the need increased due to an increase in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040. In 2025, the resource need is 1,867 MW, an increase of 240 MW, or approximately 15 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP. The most recent load forecast is even higher than that assumed in the 2021 IRP Update.

Moreover, now that the 2020 All Source Request for Proposals (2020AS RFP) has ended, PacifiCorp was unable to execute firm contracts with all projects on the final shortlist. Due to national tariff policies, global supply-chain issues, and inflationary pressures, some projects on the 2020AS RFP final shortlist were unable to move forward. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. This under-procurement adds to our need for new resources.

Q. How does the Company's 2021 IRP relate to the 2021 CEIP?

A. The CEIP represents a Washington-specific plan to meet the needs of the Company's Washington customers. This includes developing interim and specific targets to meet the ambitious goals of Washington's CETA, among others, creating customer benefit indicators, detailing specific actions, estimating incremental costs for these actions, and providing for robust public participation.[2] The economic analysis supporting the CEIP is derived from the Company's IRP analyses.

Q. Do the Company's IRP and IRP Updates analyze the cost-effectiveness of continued operation of its coal fleet?

A. Yes. These documents examine PacifiCorp's existing coal plants as part of determining the least-cost, least-risk portfolio of resources to serve customers. This examination includes analyzing the early retirement and conversion to natural gas of coal plants while appropriately considering the potential avoidance of incremental environmental compliance costs, which represents a potentially significant benefit in early closure scenarios.

Q. Were the retirement dates of any coal units driven by environmental requirements in the 2021 IRP?

A. Yes, the retirement dates for Craig Unit 2, Hayden Units 1 and 2, and Naughton Units 1 and 2 are driven by environmental requirements.

[2] PacifiCorp's 2021 CEIP (Dec. 30, 2021) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/ceip/PAC-CEIP-12-30-21_with_Appx.pdf).

Q. Did PacifiCorp's preferred portfolio of resources in the Company's 2021 IRP include the Jim Bridger conversion?

A. Yes. In the 2021 IRP, the Company evaluated a number of scenarios specific to the valuation of Jim Bridger Units 1 and 2 that excluded and included the conversion of these units to natural gas fueled operation. The Company concluded that the portfolio that eliminated gas conversion of Jim Bridger Units 1 and 2 was significantly higher cost than the portfolio that included its inclusion across each of the price-policy scenarios,[3] and included the resources as part of the least-cost, least-risk 2021 IRP preferred portfolio.[4]

Q. Please describe key factors for including the Jim Bridger conversion in the 2021 IRP preferred portfolio.

A. The Company evaluated several alternatives, including the addition of new renewable generation resources, alternative coal unit retirement timing, regional haze compliance operating limits, and gas conversions or installation of carbon capture, utilization and storage. On a risk-adjusted basis, the portfolio without natural gas conversion of Jim Bridger Units 1 and 2 results in approximately $469 million higher costs than the preferred portfolio.

Q. Was the Jim Bridger conversion included in the 2021 IRP Update?

A. Yes. The conversion of Jim Bridger Units 1 and 2 were included in the preferred portfolio identified in the 2021 IRP Update.[5] This is consistent with the substantial

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[3] PacifiCorp 2021 IRP, Vol. 1, at 270 (Sept. 1, 2021) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf).

[4] *Id.* at Ch. 1 Action Plan, Action Item 1c, at 24.

[5] PacifiCorp 2021 IRP Update, Ch. 7 Action Plan Status update, Action Item 1c, at 98 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf).

and increased need for additional generation resources first identified in the 2021 IRP, and then confirmed in the 2021 IRP Update.

Q. Was the Jim Bridger conversion addressed in the 2021 draft and final CEIPs?

A. Yes. The Company's draft CEIP noted that economic analysis supported converting Jim Bridger units to natural gas, including a statement that the Company did not anticipate allocating any of the converted Jim Bridger units to Washington.[6] However, the Company received public comments from various stakeholders, including the Alliance of Western Energy Consumers and Washington Utilities & Transportation Commission (Commission) Staff, questioning this assumption.[7] In response to this feedback, the Company's final CEIP removed the statement.[8]

B. <u>Modeling Assumptions</u>

Q. Please summarize the natural gas and CO2 price assumptions used in the economic analysis for Jim Bridger.

A. The economic analysis of Jim Bridger included five different price policy-scenarios—medium natural gas prices paired with medium CO_2 prices (MM); low natural gas prices without a CO_2 price (LN); medium natural gas prices without a CO_2 price (MN); high natural gas prices paired with high CO_2 prices (HH); and under medium gas prices and the social cost of greenhouse gases (SCGHG). While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the additional scenarios provide additional helpful analyses.

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[6] *In re* PacifiCorp's CEIP, Docket No. 210829, Draft CEIP, at 16 (Nov. 01, 2021) (https://apiproxy.utc.wa.gov/cases/GetDocument?docID=4&year=2021&docketNumber=210829).
[7] PacifiCorp 2021 CEIP, Stakeholder Input and Responses, comments 241, 329.
[8] *Compare* PacifiCorp Draft CEIP, at 16, *with* PacifiCorp's Final CEIP, at 19.

These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO2 policy assumptions affect net-power cost (NPC) benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the natural-gas conversion. Because wholesale power prices and CO2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO2 price assumptions are summarized in Table 1.

Table 1. Jim Bridger Price-Policy Assumptions

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.44	$9.93/ton starting in 2025 rising to $57.94/ton in 2040
LN	$2.94	None
MN	$4.44	None
HH	$5.64	$22.57/ton starting in 2025 rising to $102.48/ton in 2040
SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated March 31, 2021, which was the most current OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, April 2021 is the prompt month in this analysis. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecasted prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios—zero, medium, high, and a price forecast that aligns with the SCGHG. The medium and high scenarios are derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO2 price assumptions used by peer utilities. Both scenarios apply a CO2 price as a tax beginning 2025. PacifiCorp incorporated the SCGHG that is assumed to start in 2021, and the SCGHG price is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling).

Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of its analysis of Jim Bridger?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client "off-the-shelf" subscription services.

Q. Does including potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will drive reduced emissions over the life of Jim Bridger. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier as discussed above, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning. The most recent example of this trend is the Environmental Protection Agency's proposed Ozone Transport Rule (OTR) restricting nitrogen oxide (NO_x) emissions from power plants and other industrial sources. This rule could impose new environmental compliance obligations beginning in 2023 and 2024 on coal units in Utah and Wyoming, respectively, with more severe limitations applicable in both states by 2026.

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for zero-emission resources or customer preferences.

Q. How were these portfolios examined for economic viability?

A. The Company's five price-policy scenarios were analyzed to provide a deterministic PVRR(d), a risk-adjusted PVRR(d), and the levelized benefits or costs of Jim Bridger

Units 1 and 2 on a dollar-per-megawatt-hour (MWh) basis. These price-policy scenarios are discussed below.

C. Price-Policy Scenario Results

Q. Please summarize the PVRR(d) and levelized results for Jim Bridger Units 1 and 2.

A. Table 2 summarizes the PVRR(d) between cases, with and without Jim Bridger Units 1 and 2.[9]

Table 2. Jim Bridger Units 1 and 2 (Benefits)/Costs

Price-Policy Scenario	PVRR(d) ($ million)	Net Benefit ($/MWh)
HH	($515.20)	($321.79)
MN	($595.67)	($609.59)
MM	($656.41)	($174.87)
LN	($378.79)	($237.21)
MM-SCGHG	($271.68)	($17.57)

Converting Jim Bridger Units 1 and 2 to operate on natural gas is expected to deliver $656.41 million in present-value net customer benefits in the MM scenario, $515.20 million in the HH scenario, and $271.68 million in the MM-SCGHG scenario. Under the MM, HH and MM-SCGHG scenarios, nominal levelized net benefits are $174.87/MWh, $312.79/MWh, and $17.57/MWh, respectively. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance, strongly support the conversion of Jim Bridger Units 1 and 2.

IV. ROCK CREEK I AND II

Q. Please describe the acquisition of the Rock Creek Projects.

A. As described in the testimony of Company witness Ryan D. McGraw, Exhibit

[9] Exhibit No. TRB-2 Jim Bridger Analysis

RDM-1T, PacifiCorp is acquiring 190 MW Rock Creek I and 400 MW Rock Creek II facilities. Both projects will be built by Invenergy under build-transfer agreements (BTAs), and will be transferred to the Company on completion of the projects. My testimony below provides the economic justification for the Company's decision to acquire both projects.

A. <u>Need</u>

Q. Does PacifiCorp have a need for The Rock Creek Projects?

A. Yes. As discussed above, PacifiCorp's 2021 IRP identifies a significant need for new resources over the near term. This need grew when the Company prepared its 2021 IRP Update. And as discussed below, this need has grown further due to an updated load forecast and due to an under procurement of new solar and battery resources from the 2020AS RFP.

Q. Are the Rock Creek Projects a part of the 2021 preferred portfolio?

A. Yes. As discussed above, the 2021 IRP preferred portfolio includes 1,792 MW of new wind generation resulting from the 2020AS RFP, which includes 590 MW from Rock Creek I and II.[10]

Q. Please describe key factors that support including the Rock Creek Projects in PacifiCorp's 2021 IRP preferred portfolio.

A. The Rock Creek Projects are expected to meet the Company's near-term resource need and provide significant customer benefits by providing zero-fuel cost generation and substantial PTC benefits, while mitigating risks associated with future regulation of carbon-emitting resources.

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[10] *Id.* at Vol. I, Ch. 9.

Q. Please describe the reliability benefits of projects like the Rock Creek Projects.

A. Acquiring the Rock Creek Projects reduces the Company's exposure to price and volume volatility by reducing the need for market purchases. Increased reliance on the market exposes customers to price volatility and price spikes that occur when the region experiences severe weather events or system disruptions. Such events increase net power costs, and the magnitude of increase is directly proportional to the volume of purchases needed. In short, there is no guarantee that there will be a seller when PacifiCorp needs to make a short-term purchase to serve its load. This risk also exists for firm forward market purchases, where the seller could cut scheduled deliveries and accept liquidated damages if they do not have sufficient supply to meet their contractual obligations of the sale. As discussed in Company witness Link's testimony, WECC and NERC reliability studies highlight the risks of resource shortfalls across the region in the coming years.

Q. How do these studies relate to the Rock Creek Projects?

A. Each of these studies confirm the generally accepted understanding that the west is facing increasing resource adequacy risks in the near term. More recently, NERC further confirmed these findings and warned in its 2022 Summer Reliability Assessment that several regions in North America were at high or elevated risk of power outages this past summer due to above-normal temperatures and drought conditions, particularly in the western half of Canada and the United States.[11]

[11] 2022 Summer Reliability Assessment, North American Electric Reliability Corporation (May 2022) (https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf).

The Rock Creek Projects will help mitigate against the risk that there may be inadequate supply to support market purchases and reduce exposure to price spikes in periods where demand threatens to exceed supply for market purchases.

Q. Were the Rock Creek Projects selected in the 2020AS RFP?

A. Yes. As discussed in Company witness Link's testimony, the 2020AS RFP final shortlist included six final shortlist bids representing over 1,600 MW of wind generation that seek to interconnect to PacifiCorp's transmission system. These bids include the Rock Creek Projects, which were the only two bids that are not PPAs.

Q. Following their selection to the 2020AS RFP final shortlist, did the Company begin negotiating the BTA for the Rock Creek Projects?

A. Yes. Both Rock Creek I and Rock Creek II were proposed by the same developer (Invenergy) and, as discussed by Company witness McGraw, the Company engaged in BTA negotiations with Invenergy for both projects.

Q. Were these negotiations impacted by current economic conditions?

A. Yes. Bidder development efforts were challenged by importation restrictions related to China, COVID-19 international impacts, and hostilities in Ukraine that created significant logistics and supply chain challenges associated with solar panels, wind turbines, lithium batteries, transformers, and many balance-of-plant materials. As a result, many developers have been forced to abandon established supply chains and revert to new suppliers (if available), that has materially impacted overall renewable power plant pricing and commitments toward project in-service dates.

Given PacifiCorp's need for generation resources, PacifiCorp allowed pricing adjustments from all final shortlist projects from the 2020AS RFP, as well as limited extensions to commercial operations dates. Despite this additional flexibility, some of the bids from the final shortlist were unable to provide firm prices and were not available for selection. As noted earlier, this contributed to an under procurement of 902 MW of solar capacity and 497 MW of battery capacity.

Q. Have current economic conditions impacted costs for the Rock Creek Projects relative to the costs offered in the initial bids that were used to establish the final shortlist?

A. Yes. Given the market dynamics discussed above, the overall costs for the Rock Creek Projects have increased from their bids in the 2020AS RFP. The economic analysis below is based on updated project costs.

Q. Were there any additional benefits associated with the Rock Creek Projects that offset the increased costs?

A. Yes. PacifiCorp's original economic analysis in the 2020AS RFP assumed that the Rock Creek Projects qualified for a 60 percent PTC through the first ten years of operation. As a result of the IRA, the economic analysis in this case reflects the value of the 110 percent PTC, in addition to the updated project costs. These updates cause a significant and positive change in the economic benefits of the Rock Creek Projects.

Q. Have current economic drivers also impacted the Company's resource needs?

A. Yes. While the costs of 2020AS RFP bids have increased, the Company's resource needs have also increased. It is also important to consider the broader regional capacity need that aligns with the Company's need, and expected in-service date for the Rock Creek Projects. The 2020AS RFP included virtually every potential non-market resource in the region capable of achieving commercial operation by 2025. Meeting this near-term need with physical assets that will provide incremental generation capacity effectively limits the Company's options to bidders in the 2020AS RFP.

Therefore, the 2020AS RFP bids and the Rock Creek Projects remain necessary to reliably serve customers, including customers in Wyoming, and the Rock Creek Projects' selection in the RFP confirms it is part of the least-cost, least-risk resources available to meet the Company's need.

Q. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[12]

Q. Were the Rock Creek Projects included in the Company's 2021 IRP Update preferred portfolio?

A. Yes.[13]

Q. What other important updates were included in the 2021 IRP Update modeling?

A. As discussed in Chapter 5 of the 2021 IRP Update, key updates in addition to the load-and-resource balance include the resource changes due to 2020AS RFP activity, which is discussed further below. Importantly, the EPA's pre-publication version of the OTR, released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Does the 2021 IRP Update consider the reliability issues related to reliance on market purchases?

A. Yes. Given near-term concerns over resource adequacy, and because of the acquisition of additional resources including the Rock Creek Projects, the 2021 IRP

[12] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022).
[13] PacifiCorp 2021 IRP Update, Ch. 7, Action Item 2e, at 103 (Mar. 31, 2022).

Update's preferred portfolio shows generally lower market purchases in the first five years relative to the 2021 IRP preferred portfolio.[14]

Q. Were the Rock Creek Projects considered in the Company's 2021 CEIP?

A. Yes.[15]

B. Assumptions and Methods

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis of the Rock Creek Projects.

A. The economic analysis of the Rock Creek Projects included three price-policy scenarios—the MM, MN, and LN price-policy scenarios.[16] These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Rock Creek Projects. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 3 summarizes the price-policy scenarios used to analyze the Rock Creek Projects.

[14] *Id.* at Figure 1.11.

[15] PacifiCorp 2021 CEIP, Ch. 3, Table 3.2 (Dec. 30, 2021).

[16] The Company did not include a high gas price/no CO_2, high gas/medium CO_2, or medium gas/SCGHG price policy as these analyses would be less insightful. All scenarios have either higher avoided natural gas fuel costs or carbon prices, that each result in procuring more alternative resources, and greater savings and customer benefits from Rock Creek. This is intuitive, because higher natural gas costs or carbon prices decrease the demand for natural gas, but alternative emitting resources would still have a higher cost than Rock Creek, resulting in more incremental savings from resources like Rock Creek that have no variable fuel costs.

Table 3. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.52	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	$4.52	None
LN	$2.92	None
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's OFPC dated June 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2020AS RFP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (June 30, 2022, in this case). As such, these 36 months are market forwards as of June 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecasted prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used two different CO_2 price scenarios—zero and medium. The medium scenario is derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. The resulting CO_2 price is applied as a tax beginning in 2025.

Q. Did PacifiCorp update its load forecast in its analysis of the Rock Creek Projects?

A. Yes. The Company used a sales and load forecast that was completed in May 2022.

Q. How does the May 2022 forecast compare to the load forecast used in the 2021 IRP?

A. Figures 1 and 2 show PacifiCorp's May 2022 load and peak forecast relative to the 2021 IRP before incremental energy efficiency savings. A higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption expectations. The updated load forecast also accounts for updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP.

On average, over the 2023 through 2040 timeframe, forecasted system load is up 13.6 percent per year and forecasted coincident system peak is up 14.1 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the May 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.04 percent for load and 1.66 percent for peak.

Figure 1. Forecasted Annual System Load

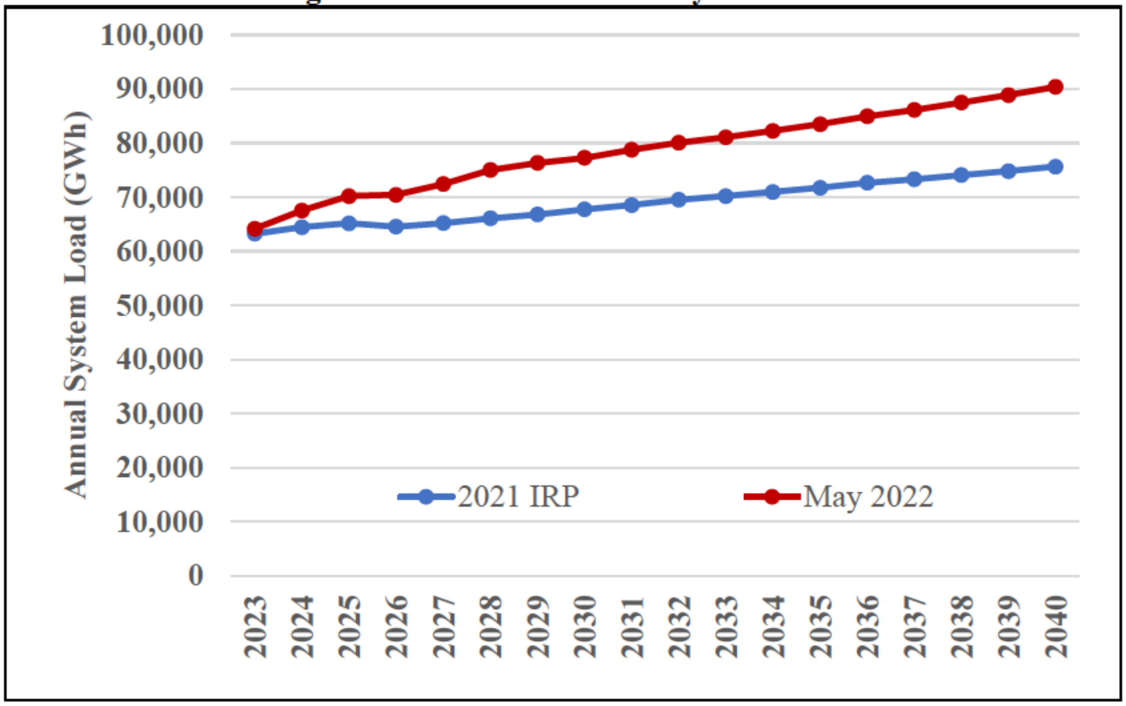
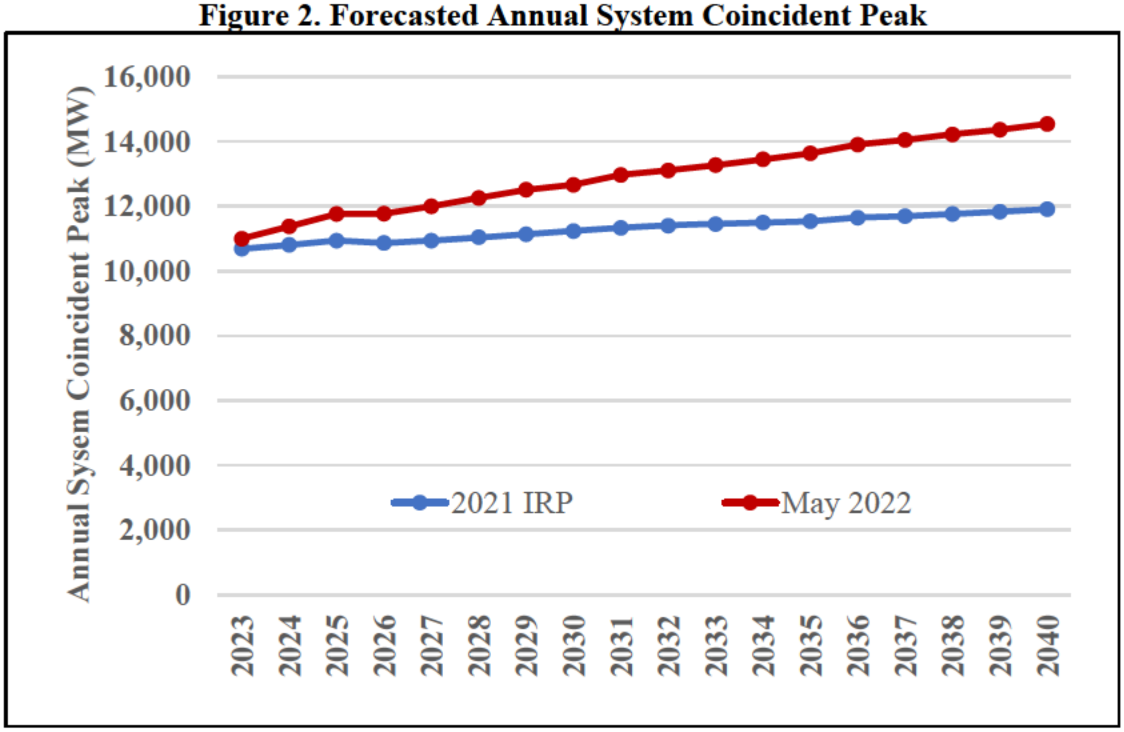


Figure 2. Forecasted Annual System Coincident Peak



Q. Has PacifiCorp incorporated the EPA's proposed OTR in its analysis of the Rock Creek Projects?

A. Yes. PacifiCorp modeled two primary components to reflect the OTR: NOx allowance requirements for each of its units including penalties for units with high emissions rates, and a dispatch target or shadow price for NOx allowances, which is used to avoid producing NOx emissions during periods when the economic benefits are relatively low. After running the model, PacifiCorp compared the results to forecasts of its annual allocation of NOx allowances for Utah and Wyoming.

Q. Please describe how the annual allocation of NOx allowances would work under the proposed rule.

A. The proposed rule calls for dynamic budgeting of NOx allowances in 2025 and beyond, with available allowances allocated among resources within a state based on the recent historical heat input and emissions rates of each resource. Under EPA's proposed rule, the forecasted allocation of NOx allowances drops significantly in 2026, as EPA assumed that selective catalytic reduction ("SCR") installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah would be covered by the rule beginning 2023 and thermal facilities in Wyoming could be covered by the rule beginning 2024.

While trading of NOx allowances among participating states is allowed, the proposed OTR includes significant penalties if a state's emissions exceed 121 percent of its annual allocation. Limited banking of NOx allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of its annual allocation. To avoid such penalties, PacifiCorp's Nox emissions during the ozone season (May-September) in each state cannot exceed 121 percent of PacifiCorp's forecasted allocation of NOx allowances for that state.

Q. Please describe how PacifiCorp developed NOx allowance requirements for each of its units.

A. In general, an allowance for one ton of NOx emissions would allow the holder of the allowance to emit one ton of NOx. However, starting in 2027,[17] the proposed OTR also imposes a daily NOx emissions rate limit of 0.14 lb/MMBtu for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an effective allowance requirement of 0.32 lb/MMBtu.[18] To calculate PacifiCorp's NOx allowance requirements under the OTR, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances.

Q. Please describe how PacifiCorp developed a dispatch target to manage its Nox allowance requirements.

A. While trading is allowed under EPA's proposed OTR, the restrictions on inter-state transfers limit the number of potential counterparties. PacifiCorp's generation fleet is an appreciable portion of the electric generating units in both Utah and Wyoming, so the potential counterparties that could have allowances available for sale within those

[17] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

[18] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

states is quite limited. With that in mind, PacifiCorp's current planning assumes that it will comply with the OTR using only its own combined allocation of NOx allowances, and is meant to ensure that its annual allowance requirements do not exceed 100 percent of the sum of its Utah and Wyoming allowance allocations. When combined with state-specific limits previously described, while either PacifiCorp's Utah or Wyoming NOx allowance requirements could be up to 121 percent of that state's allocation, any increase in one state would have to be accompanied by a reduction in emissions allowance requirements from PacifiCorp resources in the other state.

PacifiCorp's primary production cost analysis relies upon PLEXOS ST modeling that identifies system costs for a single deterministic set of expected or normal input conditions. In reality, and in stochastic modeling the Company performs using the PLEXOS MT model, significant variations in inputs such as load, hydro generation, and thermal availability are a normal course of operations. Each of these inputs can unexpectedly increase PacifiCorp's need for NOx emission allowances. Because banking and trading are limited under the OTR, variations in NOx emissions that might otherwise average out over time must comply in every year and under every set of conditions. As a result, the NOx allowances used under "normal" input conditions will likely need to be somewhat below the forecasted limit to ensure sufficient allowances are available to meet unexpected input conditions.

PacifiCorp's analysis indicated that using a NOx allowance dispatch target of [redacted] in the ST model would result in NOx allowance requirements that were under PacifiCorp's forecasted allocation and would leave sufficient allowances to meet a range of potential "above-normal" conditions. Whenever the incremental value of using a high NOx emitting resources exceeds the dispatch target price, the model will deploy the high NOx resource, rather than lower NOx alternatives, which are typically gas-fired resources or market transactions. For a coal-fired resource with a NOx emissions rate of 0.20 lb/MMBtu, the NOx dispatch target price means that the resource would not be dispatched unless it provides at least [redacted] in incremental value relative to no NOx alternatives, or a proportional amount of incremental value relative to lower NOx alternatives.[19]

The dispatch target price is used to direct the model to avoid emissions, and is not a direct cost, as the Company would receive its allowance allocation free of charge under the proposed rule. While the Company could potentially sell allowances, there is little indication what market prices may prevail, and market prices may be below this target. As a result, no direct costs or revenues for allowances are included in the analysis. The allowance requirements resulting from this dispatch target price vary over time as the OTR requirements take full effect and as the Company's portfolio evolves. The Company's load forecast and other modeling inputs also play a role in the resulting volumes. A comparison of the allowance requirements for the scenarios relative and forecasted allowance allocations is discussed in the Price-Policy Scenario Results section later in my testimony.

[19] A 0.20 lb/MMBTU coal-fired resource would have a NOx credit requirement of 0.32 lb/MMBTU in 2027 and beyond, as detailed in footnote 22. A typical average heat rate for a coal-fired resource is 11 MMBtu/MWh. [redacted] ÷ 2,000 lb/ton * 0.32 lb/MMBtu * 11 MMBtu/MWh = [redacted].

Q. Please describe the modeling methodology PacifiCorp used in its analysis of the Rock Creek Projects.

A. Consistent with IRP modeling practices, the Company calculated a system PVRR by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP and 2021 IRP Update. Net customer benefits are calculated as the PVRR(d) between different simulations of PacifiCorp's system. One simulation includes the Rock Creek Projects, and the other simulation excludes them. The simulation that includes both projects includes transmission interconnection costs. When the two simulations are compared, changes to system costs are attributable to both projects. These also include simulations before passage of the IRA, and after to reflect the value of increased PTCs. In all studies, the Gateway West and Gateway South transmission projects discussed in Rick Link's testimony were assumed to be in-service, and beyond 2025 proxy resource options from the 2021 IRP are available to meet system needs.

Customers are expected to realize benefits when the system PVRR from the simulation with the projects is lower than the system PVRR without. Conversely, customers would experience increased costs if the system PVRR with the projects is higher than the system PVRR without.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the wind projects?

A. Yes. PacifiCorp analyzed sensitivities that quantify how changes in capital costs and PTC values influence projected customer benefits.

C. Price-Policy Scenario Results

Q. Please summarize the PVRR(d) results post-IRA.

A. Table 4 summarizes the PVRR(d) results for each price-policy scenario from the combined projects after passage of the IRA.[20]

Table 4. Post-IRA (Benefit)/Cost of Both Wind Projects ($ million)

	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f) = (a) + (e)	(g) = (b) + (e)
Price-Policy Scenario	**PVRR(d)**	**Risk-Adjusted PVRR(d)**	**110% PTC Update**	**Project Cost Update**	**Total Update**	**Updated PVRR(d)**	**Updated Risk-Adjusted PVRR(d)**
MM	(143)	(163)	(197)	42	(155)	(298)	(318)
MN	(33)	(51)	(194)	42	(151)	(185)	(202)
LN	16	2	(195)	42	(153)	(137)	(151)

Before adjusting for risk (Column (g)), system costs are lower when the wind projects are included in the portfolio in all scenarios: ranging from a $137 million customer benefit under the LN scenario to $298 million in the MM scenario. When adjusting for risk (Column (g)), the benefits from the wind projects increase: ranging from $151 million in the LN scenario to $318 million in the MM scenario. The increase in customer benefits from the 110 percent PTC is substantial, even when accounting for the increase in project costs. This updated analysis supports the necessity of the wind projects, and indicates they will produce robust customer benefits. As discussed earlier, these benefits only increase under a high gas or a high CO_2 price-policy scenario.

Q. How do the modeled OTR allowance requirements compare to PacifiCorp's forecasted allowance allocation?

A. The annual allowance requirements in the ST-model results are generally slightly

[20] Exhibit No. TRB-3C Rock Creek Analysis

below a high estimate of PacifiCorp's allowance allocation. Based on the allocation methodology identified in the proposed rule, this high allowance allocation would likely require installation of SCR equipment at most of PacifiCorp's coal-fired generating units that are not equipped with that technology. In the absence of additional emission control equipment, PacifiCorp's allocation would be significantly lower, and well below the allowance requirements from the ST-model results. The high and low allocation forecasts and the ST-model results for the MM and MN price-policy scenarios are shown in Confidential Figure 3. As shown, allowance allocations could be significantly lower than what is assumed to be available in the current ST-model results, which would further increase the value of generation from resources without emissions, such as the Rock Creek Projects.

Confidential Figure 3. Forecasted OTR Allocation and Modeled Requirements

[redacted]

Q. Would the Rock Creek Projects provide customer benefits even if construction costs are higher than expected?

A. Yes. For both projects, a one percent increase in the initial capital costs would reduce PVRR benefits through 2040 by $9.1 million. To negate the $318 million in risk-adjusted, post-IRA benefits under the MM price-policy scenario, project costs would need to increase by 35 percent. To negate the $202 million in risk-adjusted, post-IRA benefits under the MN price-policy scenario, project costs would need to increase by 22 percent.

Q. Are the Company's economic analyses of the expected customer benefits from the Rock Creek Projects conservative?

A. Yes. The PVRR(d) results for the Rock Creek Projects do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by both projects. Customer benefits for all price-policy scenarios would improve by approximately $14 million for every dollar assigned to the incremental RECs that will be generated through 2040 by both projects. And these RECs can also be used for CETA compliance purposes, providing additional customer benefits.

Similarly, the Company's analyses understate forecasted coal coasts for certain system resources, including the Dave Johnston plant. If corrected to include the full costs of fuel supply for all plants, the Company's economic analysis would demonstrate even higher benefits for the Rock Creek Projects. Additionally, the natural gas and electricity prices in the Company's September 2022 OFPC are higher than the values assumed in the June 2022 OFPC used in the Company's analysis, which would similarly result in higher benefits for the Rock Creek Projects.

V. REPOWERING FOOTE CREEK II-IV AND ROCK RIVER I

Q. Please describe the acquisition and repowering of the Foote Creek II-IV and Rock River I wind facilities.

A. As described in the testimony of Company witness Timothy J. Hemstreet, Exhibit TJH-1T, PacifiCorp is acquiring and repowering the 43 MW Foote Creek II-IV and 49 MW Rock River I wind facilities. This involves installing approximately 11 modern Wind Turbine Generators (WTGs) at the Foote Creek facilities, and 19 WTGs at the Rock River I facility. These acquisitions and repowering will increase the power generation from, and extend the service lives of, both facilities. These new turbines will increase the power generation from the previous capability and allow customers to benefit from these favorable wind sites. My testimony below provides the economic justification for the Company's decision to acquire and repower the Repowered Facilities

A. Need

Q. Did PacifiCorp's preferred portfolio of resources developed in the Company's 2021 IRP include the Foote Creek II-IV and Rock River I facilities?

A. Yes.[21]

[21] *Id.* at Ch. 1 Action Plan, Action Item 2b, at 25.

Q. Please describe the key factors for including Foote Creek II-IV and Rock River I in the 2021 IRP preferred portfolio.

A. Both projects are anticipated to be fully online and serving customers by 2024. This timing enables both projects to deliver needed energy and capacity value for customers before the availability of either new proxy resources or final shortlist project generation expected to be enabled by the Energy Gateway South transmission line as identified in the Company's 2020AS RFP. Without both projects, the risk of shortfalls is increased as is reliance on energy markets. In their current states, the existing Foote Creek II-IV and Rock River I facilities are not operating as turbines and have been removed pending the repowering of the sites. Repowering will allow the facilities to once again provide energy and capacity to serve load and reduce market reliance, while allowing the newly installed turbines to qualify for substantial federal PTCs.

Q. Were Foote Creek II-IV and Rock River I included in the Company's 2021 IRP Update?

A. Yes.[22]

Q. Were Foote Creek II-IV and Rock River I included in the Company's CEIP?

A. Yes.[23]

[22] PacifiCorp 2021 IRP Update (Mar. 31, 2022).
[23] PacifiCorp's 2021 CEIP, at 21.

B. Assumptions and Results

Q. Has the Company performed updated analyses of the Repowered Facilities after filing the 2021 IRP?

A. Yes. The Company performed a 30-year analysis of each project's economics through end-of-life using its PLEXOS modeling system, the same modeling system used for the 2021 IRP.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analyses for the Repowered Facilities.

A. The economic analysis for each of the projects included four price-policy scenarios—representing low, medium, and high natural gas prices, and zero, medium, high, and the SCGHG CO_2 prices. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario, the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario, the price-policy scenario that pairs high natural gas prices with a high CO_2 price is referred to as the "HH" scenario, and the scenario that pairs medium natural gas prices with the SCGHG is referred to as the MM-SCGHG scenario. While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the LN, HH, and MM-SCGHG scenarios provide informative analytical bookends scenarios.

Similar to the Company's Jim Bridger analyses, these assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Repowered Facilities. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO_2 price assumptions are summarized in Table 5.

Table 5. Price-Policy Assumptions

Price-Policy Scenario	**Henry Hub Natural Gas Price (Levelized $/MMBtu)***	**CO_2 Price Description**
HH	$5.64	22.57/ton starting 2025 rising to 102.48/ton in 2040
MM	$4.44	$9.93/ton starting in 2025 rising
LN	$2.94	None
MM-SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's OFPC dated March 31, 2021, which was the most recent OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, May 2021 is the prompt month in this case. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecasted prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios—zero, medium, high, and the SCGHG. The medium scenario is derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. Both the medium and high scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp also incorporated the SCGHG that is assumed to start in 2021, and is applied such that the SCGHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling).

Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of analyzing the Repowered Facilities?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client, "off-the-shelf" subscription services.

Q. Please explain how you conducted your analyses.

A. For both projects, the methodologies are consistent with the approach used to perform the economic analysis of portfolios in the 2021 IRP. The system value of incremental wind energy for each project is calculated from two PLEXOS ST model simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. The system value of incremental wind energy is then converted to a dollar-per- MWh value by dividing the change in annual system cost by the change in incremental wind energy for both price-policy scenarios through 2040. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2038-2040 timeframe. The assumed system value, expressed in dollars per MWh, is applied to the incremental energy output associated with each of the wind repowering projects.

Q. Were your initial economic analyses of the Repowered Facilities conducted before passage of the IRA?

A. Yes.

Q. How does the IRA impact your analyses of the Repowered Facilities?

A. Based on existing law, PacifiCorp's initial economic analyses assumed that Foote Creek II-IV and Rock River I qualified for 60 percent of available PTCs. After passage of the IRA, the Company understands that the Repowered Facilities now qualify for 110 percent of available PTCs. The Company has updated its economic analyses to reflect the new PTC value for both projects, and the results are reflected in Tables 6 and 7 below.

Q. Please summarize the PVRR(d) and levelized results for Foote Creek II-IV.

A. Table 6 summarizes the PVRR(d) between cases, with and without Foote Creek II-IV acquisition and repowering, for customer benefits before and after passage of the

IRA. This table also presents the same information on a levelized dollar-per-MWh basis.[24]

Table 6. Foote Creek II-IV (Benefits)/Costs

Price-Policy Scenario	Pre-IRA PVRR(d) ($ million)	Pre-IRA Net Benefit ($/MWh)	Post-IRA PVRR(d) ($ million)	Post-IRA Net Benefit ($/MWh)
HH	($80.80)	($38/MWh)	($104.23)	($49/MWh)
MM	($53.07)	($25/MWh)	($76.49)	($36/MWh)
LN	$17.09	$8/MWh	($6.33)	($3/MWh)
MM-SCGHG	($142.77)	($67/MWh)	($166.19)	($78/MWh)

Before passage of the IRA, Foote Creek II-IV was expected to deliver $53.07 million in present-value net customer benefits in the MM scenario, $80.8 million in the HH scenario, and $142.77 million in the MM-SCGHG scenario. This is contrasted with $17.09 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $25/MWh and $38/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $8/MWh. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering the Foote Creek II-IV project.

After passage of the IRA, customer benefits increased substantially: Foote Creek II-IV will now deliver $76.49 million in present-value net customer benefits in the MM scenario and $104.23 million in the HH scenario. Importantly, the only scenario where Foote Creek II-IV was expected to generate customer costs before passage of the IRA—the LN scenario ($17.09 million)—has transformed to a

[24] Exhibit No. TRB-4C Foote Creek Analysis

$6.33 million customer benefit. While the Company decided to move forward with Foote Creek II-IV before passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

Q. Has the Company updated its analysis of Rock River I after filing the 2021 IRP?

A. Yes. The Company updated its economic analysis in 2022 to support the Company's decision to acquire and repower Rock River I, and these results are reflected below.

Q. Please summarize the PVRR(d) and levelized results for Rock River I.

A. Table 7 summarizes the PVRR(d) between cases, with and without Rock River I acquisition and repowering, for customer benefits before and after passage of the IRA. This table also presents the same information on a levelized dollar-per-megawatt-hour basis.[25]

Table 7. Rock River I (Benefits)/Costs

Price-Policy Scenario	Pre-IRA PVRR(d) ($ million)	Pre-IRA Net Benefit ($/MWh)	Post-IRA PVRR(d) ($ million)	Post-IRA Net Benefit ($/MWh)
HH	($67.76)	($32/MWh)	($91.69)	($43/MWh)
MM	($30.15)	($14/MWh)	($54.09)	($25/MWh)
LN	$8.82	$4/MWh	($15.12)	($7/MWh)
MM-SCGHG	($143.42)	($67/MWh)	($167.35)	($78/MWh)

Before passage of the IRA, Rock River I was expected to deliver $30.15 million in present-value net customer benefits in the MM scenario, $67.76 million in the HH scenario, and $143.42 million in the MM-SCGHG scenario. This is contrasted with $8.82 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $14/MWh and $32/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $4/MWh. Company forecasting and the relative magnitude of

[25] Exhibit No. TRB-5 Rock River Analysis

benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering Rock River I.

After passage of the IRA, customer benefits increased substantially: Rock River I will now deliver $54.09 million in present-value net customer benefits in the MM scenario and $91.69 million in the HH scenario. Importantly, the only scenario where Rock River I was expected to generate customer costs before passage of the IRA—the LN scenario ($8.82 million)—has transformed to a $15.12 million customer benefit. These benefits only increase under a high gas or a high CO_2 price-policy scenario.

Q. Are the Company's economic analyses of the expected customer benefits from Foote Creek II-IV and Rock River I conservative?

A. Yes. The PVRR(d) results for Foote Creek II-IV and Rock River I do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by both projects. Customer benefits for all price-policy scenarios would improve significantly for every dollar assigned to the incremental RECs that will be generated through 2040 by both projects, and these RECs can also be used for CETA compliance purposes, providing additional customer benefits.

VI. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis shows that the conversion of Jim Bridger Units 1 and 2 to natural gas, the acquisition of Rock Creek I and II, and the acquisition and repowering of Foote Creek II-IV and Rock River I, are necessary and will provide substantial customer benefits compared to anticipated project costs.

Q. What is your recommendation?

A. As supported by PacifiCorp's economic analysis, I recommend that the Commission determine that the Company's decisions to convert Jim Bridger 1 and 2, acquire the Rock Creek Projects, and acquire and repower Foote Creek II-IV and Rock River I are prudent.

Q. Does this conclude your direct testimony?

A. Yes.