REDACTED
Docket No. 20000-___-ER-23
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Rick T. Link

March 2023

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning, Procurement and Optimization.

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's energy supply management and resource planning and procurement functions, which includes the integrated resource plan ("IRP"), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and conducting competitive request for proposal ("RFP") processes, consistent with applicable state procurement rules and guidelines.

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource and transmission investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, 2019, and 2021 IRPs; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource and transmission investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management degree from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Wyoming Public Service Commission ("Commission"), Washington Utilities and Transportation Commission, the Idaho Public Utilities Commission, the Utah Public Service Commission, the Public Utility Commission of Oregon, and the California Public Utilities Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I provide economic analysis that supports PacifiCorp's decision to build two transmission projects and acquire one wind generation resource. These projects include: (1) Gateway South, a 416-mile, 500-kilovolt ("kV") transmission line from the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah; (2) Gateway West Segment D.1, a 59-mile, 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming and the accompanying ancillary facilities (collectively I refer to Gateway South and Gateway West Segment D.1 as the "Transmission Projects"); and (3) Rock Creek I, a 190-megawatt ("MW") wind facility located in Carbon and Albany counties in southeast Wyoming ("Rock Creek I").

I also summarize PacifiCorp's need for the Transmission Projects, provide background on PacifiCorp's 2020 all-source RFP ("2020AS RFP") to solicit new resources, including those enabled by the Transmission Projects, and discuss customer benefits that result from the projects.

For details regarding the Transmission Projects, please refer to the Direct Testimony of Company witness Mr. Rick A. Vail, and to Company witness Mr. Ryan D. McGraw for details regarding Rock Creek I.

Q. Please summarize your testimony on the Transmission Projects.

A. The 2021 IRP confirmed that the Transmission Projects are key transmission investments that will enable the procurement of low-cost wind facilities to reliably meet the Company's need for additional resources. These resources are expected to produce significant customer benefits. This includes ensuring that all new wind resources from the 2020AS RFP that depend on the Transmission Projects: (1) qualify for 110 percent of available federal production tax credits ("PTCs"), further reducing the cost of these resources (that already have no fuel costs or emissions) relative to other resource options; and (2) generate renewable-energy credits ("RECs") that can be sold in the market to create additional revenues that would offset costs.

As discussed by Mr. Vail, the Transmission Projects will also provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Importantly, the Transmission Projects ensure the Company will meet its obligations to reliably accommodate nearly 2,500 MW of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This includes 500 MW of firm point-to-point ("PTP") transmission service to a third-party transmission customer under the Federal Energy Regulatory Commission's ("FERC") jurisdiction. Moreover, the Transmission Projects create additional opportunity to increase transfer capability with the construction of additional segments of the Energy Gateway project.

Q. Please summarize your economic analysis of the Transmission Projects.

A. My economic analysis demonstrates that the Transmission Projects are necessary and in the public interest. In my analysis, I reviewed the change in revenue requirement due to the Transmission Projects, and associated resources that are dependent upon the Transmission Projects, using the Company's IRP modeling tool across five different scenarios that pair varying natural gas price assumptions with varying carbon dioxide ("CO_2") policy assumptions (price-policy scenarios). For each price-policy scenario, I calculated the change in system revenue requirement between cases with and without the Transmission Projects through 2040, where capital revenue requirement is levelized. The price-policy scenarios include:

- Medium natural gas prices paired with medium CO_2 prices ("MM");
- Medium natural gas prices without a CO_2 price ("MN");
- High natural gas prices paired with high CO_2 prices ("HH");
- Low natural gas prices without a CO_2 price ("LN"); and
- The Social Cost of Greenhouse Gas ("SCGHG").

These analyses confirm that the Transmission Projects are expected to generate customer benefits. Under the MM price-policy scenario, the present-value revenue requirement differential ("PVRR(d)") customer benefit when using the most conservative assumptions for unavoidable transmission is $128 million and the risk-adjusted PVRR(d) benefits are $260 million. When assuming the cost of the Transmission Projects are unavoidable, the PVRR(d) under the MM price-policy scenario yields a $610 million customer benefit and a risk-adjusted benefit of $742 million. Conservatively, these benefits do not assign any value to the RECs that will be generated by new resources made available due to the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Q. Did you develop an additional calculation to measure how changes in cost might influence customer benefits?

A. Yes. I produced a calculation to determine how changes in resource and transmission cost assumptions would impact customer benefits. My review of resource costs show that assumed initial capital costs would need to increase by 32 percent to erode the customer benefits from the MM price-policy scenario. Similarly, the cost of the Transmission Projects, informed by the Company's recent experience with building Gateway West Segment D.2, would need to increase by 50 percent to erode the benefits from the MM price-policy scenario. These results show that the projected customer benefits are robust, and that they persist even if the resource costs and transmission costs far exceed the estimates that were available when we committed to move forward with the Transmission Projects.

Q. Did you continue to review the economic analysis after the Company began construction of the Transmission Projects?

A. Yes. I revisited the economic analysis as we were finalizing contracts for the wind resources dependent upon the Transmission Projects. This update accounted for, among other things, higher costs, higher PTC values associated with the passage of the Inflation Reduction Act ("IRA"), and the potential impacts of the Ozone Transport Rule ("OTR"). This review showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario.

Q. Please summarize your testimony regarding Rock Creek I.

A. The 2021 IRP and 2021 IRP Update confirmed that the final shortlist of bids from the 2020AS RFP, which included Rock Creek I, is necessary to meet the Company's need for additional resources to reliably serve customers. In 2025, the first full year that includes Rock Creek I's operation, the 2021 IRP indicated a need for 1,627 MW of new resources, while the 2021 IRP Update identified a need for an additional 240 MW.

The Company's most recent load forecast has also increased, resulting in a system coincident peak load in 2025 that is over 800 MW higher than the Company's peak load assumed in the 2021 IRP. This significant resource need coincides with an expected regional capacity shortfall in 2025, which makes Rock Creek I even more critical to ensuring sufficient capacity to reliably meet customer needs.

Similar to the Transmission Projects, Rock Creek I will also produce significant customer benefits because it: (1) qualifies for 110 percent of available PTCs, further reducing the cost of the resource (that already has no fuel costs or emissions) relative to other resources; and (2) generate RECs that can be sold in the market to create additional revenues that would offset costs.

Q. Please summarize your economic analysis of Rock Creek I.

A. My economic analysis demonstrates that Rock Creek I is in the public interest. In my analysis, I reviewed the change in revenue requirement due to Rock Creek I using the Company's IRP modeling tool across different scenarios that pair varying natural gas price assumptions with varying CO_2 price-policy assumptions. Similar to the Transmission Projects, these scenarios include an MM price-policy scenario, an LN price-policy scenario, and an MN price-policy scenario. For each scenario, PacifiCorp calculated the change in system revenue requirement between cases with and without Rock Creek I, where capital revenue requirement is levelized.

My economic analysis confirms that Rock Creek I is expected to provide customer benefits in all scenarios. Analysis prepared before the IRA showed $15 million of customer benefits, which increased to $20 million of benefit on a risk-adjusted basis under an MM price-policy scenario. The post-IRA analysis of both Rock Creek I and Rock Creek II, a co-located sister facility not included in this proceeding due to its later in-service date, yields customer benefits totaling $298 million, that rise to $318 million on a risk-adjusted basis under an MM price-policy scenario. Conservatively, these benefits do not assign any value to the RECs that will be generated by Rock Creek I, that can be sold in the market to create additional revenues that would offset costs.

Q. Does your testimony support the prudency of the Company's investments for all three projects?

A. Yes.

III. GATEWAY SOUTH AND GATEWAY WEST SEGMENT D.1

A. Need

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

A. Yes. The primary focus of the 2021 IRP is to forecast the need for resources and then evaluate different ways to meet that need over time. In the 2021 IRP, the assessment of resource need is presented in Volume I, Chapter 6. The load-and-resource balance shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and rising to 6,600 MW by 2040.[1] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,627 MW. Consistent with prior IRPs, all resource portfolios produced in the 2021 IRP that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, and market resources to fill this need.

This need has continued to increase due to increases 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.[2] In 2025, the first full year that includes Rock Creek I's operation, the resource need is 1,867 MW, an increase of 240 MW or approximately 15 percent from 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.[3] And, as discussed later in my testimony, the most recent load forecast is even higher that that assumed in the 2021 IRP Update.

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[1] 2021 IRP, Vol. I, Table 6.12.
[2] *Id.,* at Table 4.2.
[3] *Id.,* at 2.

Since the Company initiated construction of the Transmission Projects, national tariff policies, global supply-chain issues, and inflationary pressures eliminated some bids on the 2020AS RFP final shortlist. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. Additional resources are needed to reduce PacifiCorp's reliance on the market.

Q. Why it is important to reduce PacifiCorp's reliance on market purchases?

A. There is a strong consensus that the western United States will face an increasing capacity deficit in the near future.[4] For example, in December 2020, the Western Electricity Coordinating Council ("WECC") issued its Western Assessment of Resource Adequacy Report ("WARA").[5] The WARA was developed based on data collected from balancing authorities describing their own demand and supply projections over the next ten years. The WARA evaluated resource adequacy among six subregions under two scenarios—one with and without imports to the subregion. PacifiCorp serves load in three of these subregions—Northwest Power Pool Northwest ("NWPP-NW"), Northwest Power Pool Northeast ("NWPP-NE"), and Northwest Power Pool Central ("NWPP-C"). For each of these scenarios, the WARA considered variations of supply. The most conservative assumes availability of only existing resources, and the most liberal includes availability of new resources under construction, those expected to come online, and those under development. The study found that for each of the three subregions in which PacifiCorp serves load, imports are needed to meet a one-day in ten-year planning threshold. The WARA shows that

[4] *Id.,* at Vol. I, Ch. 5.

[5] *The Western Assessment of Resource Adequacy Report,* Western Electricity Coordinating Council (Dec. 18, 2020).

the NWPP-NW subregion would fall short of the planning threshold in 194 hours (under the most liberal supply case) to 208 hours (assuming availability of only existing resources) without imports. In the NWPP-NE and NWPP-C subregions, the study found that planning threshold is not met in 4,200 hours without imports.

These findings highlight that there are real reliability risks associated with relying on supply being available in the market to meet projected load obligations. In addition, WECC's 2021 WARA issued December 2021 further concludes that not only are resource adequacy risks to reliability likely to increase over the next ten years, it recommends entities take immediate action to mitigate near-term risks and prevent long-term risks. The 2021 WARA projects that "by 2025, each subregion, and the interconnection, will be unable to meet the 99.98%-one-day-in-ten-year-reliability threshold."[6]

Q. Are there any other third-party studies confirming the resource adequacy concerns in the west?

A. Yes. In December 2020, the North American Electric Reliability Corporation ("NERC") issued its Long-Term Resource Adequacy ("LTRA") study that included its ten-year WECC region reliability assessment.[7] The NERC LTRA calculates an anticipated resource-based reserve margin to a reference reserve margin to establish one of three risk determinations—adequate (anticipated margin exceeds the reference margin), marginal (anticipated margin is below the reference margin, but new resources

[6] *2021 Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec. 17, 2021) (available here).
[7] *2020 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2020).

under development could cover the shortfall), and inadequate (anticipated reserve margin is below the reference margin and load interruption is likely).

The NERC LTRA shows that the Northwest Power Pool region and Rocky Mountain Reserve Group regions are projected to be inadequate beginning in 2028 even if resources under development come online. Again, these findings highlight the risk of relying on other entities in the region to have excess supply available for the market when PacifiCorp may be required to buy power to serve its customers.[8]

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

A. The 2021 IRP preferred portfolio represented PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, based on the information available at the time the plan was developed. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflected a cost-conscious plan with near-term investments in renewable resources that 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. Are the Transmission Projects a part of the 2021 IRP preferred portfolio?

A. Yes. As described in Volume I, Chapter 4 of the 2021 IRP, the preferred portfolio includes both Gateway South and Gateway West Segment D.1. In the 2021 IRP, the Transmission Projects are assumed to be placed in service by the end of 2024,

[8] *2021 Long-Term Reliability Assessment,* North American Electric Reliability Corporation (Dec. 2021) (indicating resource adequacy needs in next ten years, with shortfalls appearing earlier (in 2026) based on existing resources).

consistent with current construction timelines discussed by Mr. Vail. The Transmission Projects will enable the addition of new wind facilities that contribute to meeting 1,627 MW of projected resource need beginning 2025.

Q. What new transfer capabilities and interconnection capacity do the Transmission Projects add to PacifiCorp's system?

A. The Transmission Projects will increase the transfer capability between the Aeolus substation in eastern Wyoming and the Clover substation located near Mona, Utah by 1,700 MW, and enable the interconnection of 2,030 MW of new resources in eastern Wyoming.

Q. Please describe key factors supporting the inclusion of the Transmission Projects as prudent investments in this case.

A. The Transmission Projects allow PacifiCorp to implement system improvements, support the full capacity rating of Gateway South and West, and enable the addition of incremental Wyoming renewable resources to support customer needs and deliver value for customers in the most cost-effective way. As discussed by Mr. Vail, the Transmission Projects will also improve overall reliability of the transmission system and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Importantly, the Transmission Projects ensure the Company will meet its obligations to reliably accommodate nearly 2,500 MW of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This includes 500 MW of firm PTP transmission service to a third-party transmission customer under the FERC's jurisdiction.

Q. Please describe the reliability benefits of the Transmission Projects.

A The Transmission Projects directly connect eastern Wyoming to central Utah while enhancing reliability throughout PacifiCorp-served regions. Connecting to the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah.

Moreover, allowing additional generation resources to interconnect and serve load will lessen PacifiCorp's reliance on volatile and potentially diminishing market transactions to serve load. Given concerns over regional resource adequacy, reducing reliance on the market ensures a stable and reliable supply of capacity and energy going forward.

In addition, Gateway South improves reliability by relieving the stress on the transmission system in eastern Wyoming and central Utah. Gateway South relieves stress on the underlying 230-kV transmission system in Wyoming, and it unloads the underlying 345-kV transmission system in central Utah, improving reliability in both regions. Essentially, the 500-kV line brings two distant areas closer to each other in a way that improves regional reliability.

Gateway West Segment D.1 creates a new transmission path that allows for additional resource development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Gateway West Segment D.1 is also a prerequisite for interconnecting new resources, including those selected in the 2020AS RFP. Mr. Vail's testimony addresses transmission system reliability and interconnection issues in greater detail.

B. The 2020AS RFP

Q. Please provide an overview of the 2020AS RFP.

A. The 2020AS RFP was issued to identify resources that could meet the Company's projected resource need identified in the 2019 IRP. Based on the cost-and-performance assumptions for proxy resources in the 2019 IRP, the Company expected that new wind, solar and battery energy storage systems ("BESS") were likely to be the most cost-competitive types of resources offered into the 2020AS RFP. However, bidders could offer proposals for other types of resources (*i.e.*, natural gas, pumped storage, *etc.*).

Q. When was the 2020AS RFP issued?

A. After receiving approval from the Utah (Docket No. 20-035-05) and Oregon Commissions (Docket No. UM 2059), PacifiCorp issued the 2020AS RFP on July 7, 2020.[9]

Q. What was the market response to the 2020AS RFP?

A. There was a robust market response that resulted in over 28,000 MW of conforming bids, with an additional 12,500 MW of non-confirming bids. Bids for 24 projects totaling over 9,000 MW of resource capacity located in eastern Wyoming were submitted.

Q. How did the Company evaluate submitted bids?

A. The Company created an initial shortlist that was made public on October 29, 2020.

[9] In Oregon Administrative Rules 860-89-0010, et seq., the Oregon Commission has established competitive bidding requirements for certain resource acquisitions by Oregon's investor-owned utilities. *In the Matter of the Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324, Appendix A (Aug. 30, 2018). In addition, Utah's Energy Resource Procurement Act requires a competitive solicitation process before the acquisition of renewable resources greater than 300 MW *See* Utah Code Ann. § 54-17-201 *et. seq.*

This shortlist included 5,453 MW of renewable resource capacity: 2,974 MW of solar or solar with storage (1,130 MW of battery storage), 2,479 MW of wind, and 200 MW of standalone BESS. PacifiCorp then initiated a capacity factor evaluation process (performed by third-party expert WSP Global). The initial shortlist contained a mix of various ownership structures, including proposals for power-purchase agreements ("PPAs"), build-transfer agreements ("BTAs"), and battery storage agreements ("BSAs").

Q. What resources were selected to the final shortlist?

A. After evaluating a range of potential bid portfolios, and accounting for bid updates from interconnection study results, the final shortlist included: 1,792 MWs of new wind capacity (590 MWs as BTAs and 1,202 as PPAs); 1,302 MW of solar capacity as PPAs; 697 MW of BESS (497 MW of BESS capacity paired with solar bids, and 200 MW as standalone BESS capacity as a BSA).[10]

Q. Which final shortlist resources depend on the Transmission Projects for interconnection?

A. Six final shortlist resources, representing over 1,600 MW of wind generation, require the Transmission Projects to interconnect to PacifiCorp's transmission system. Table 1 summarizes the wind resources that require the Transmission Projects to achieve interconnection.

[10] The final shortlist originally included an additional solar bid collocated with BESS. Shortly after the bidder was notified its project was on the final shortlist, it withdrew the bid from the 2020AS RFP. This bid is not included in the total capacity.

Table 1. 2020AS RFP Wind Bids Dependent on the Transmission Projects for Interconnection

Project	Bidder	Structure	Capacity (MW)
Cedar Springs IV	NextEra	PPA	350
Boswell Springs	Innergex	PPA	320
Two Rivers	BlueEarth Renewables LLC and Clearway Renew LLC	PPA	280
Anticline	NextEra	PPA	101
Rock Creek I	Invenergy	BTA	190
Rock Creek II	Invenergy	BTA	400

Q. Was the 2020AS RFP overseen by independent evaluators?

A. Yes. Consistent with Utah and Oregon Commission approvals, the solicitation process was overseen by two independent evaluators—one retained by PacifiCorp and appointed by the Oregon Commission (PA Consulting Group, Inc.), and one retained by the Utah Commission (Merrimack Energy Group).

Q. What were the independent evaluators' conclusions regarding the 2020AS RFP?

A. Both independent evaluators concluded that the process was fair and transparent, and that the bids selected for the final shortlist were reasonable.

Q. Please describe the Utah independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Shortlist Report, the Utah independent evaluator concluded that the RFP was fair, reasonable, and in the public interest.[11] In particular, the Utah independent evaluator concluded:

- The market response to the RFP was robust and, "Based on the unbelievable response from the market it is safe to say that the solicitation process resulted in a very competitive process with many more proposals generally submitted than the expected requirements by bubble identified by PacifiCorp."[12]

[11] *In re RMP 2020AS RFP Application,* Docket No. 20-35-05 (Utah Public Service Commission; September 2, 2021) (available here).
[12] Utah IE Shortlist Report at 74.

- PacifiCorp engaged the bidders throughout the process in a timely manner to ensure that all bidders were treated fairly.
- All bidders were treated the same, had access to the same information at the same time, and had an equal opportunity to compete.
- PacifiCorp implemented its evaluation and selection process consistent with its proposed evaluation and selection process as outlined in the RFP in a structured and consistent manner designed to result in the selection of a portfolio of projects that would result in a least cost solution.
- PacifiCorp subjected all bidders to the same information requirements and conducted a consistent evaluation process with all proposals treated equally in terms of the evaluation methodology and information required of each bidder.
- The selection process was unbiased with respect to ownership structures, i.e., the process did not unreasonably favor bids that resulted in a utility-owned resource.
- The selected bids resulted in lower system cost than a case where no bids were selected and maximized customer benefits while managing risk.

Q. Please describe the Oregon independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Closing Report, the Oregon independent evaluator concluded that the final shortlist reflected a diverse portfolio of competitive resources that achieves the resource adequacy and least cost goals set forth in PacifiCorp's IRP.[13] This was based on the following conclusions:

- PacifiCorp's procurement process, scoring methodology and results were fair and free of bias across all bids and bidders.
- PacifiCorp applied the rules of the 2020AS RFP in an unbiased manner, communicated transparently with the independent evaluators regarding their modelling processes and with stakeholders regarding their decisions.
- PacifiCorp's bid price scores were on average consistent with the independent evaluator's independent scoring methodology.

[13] *In re PacifiCorp's 2020AS RFP Application,* Docket No. UM 2059 (Oregon Commission; Jun. 15, 2021) (available here).

- PacifiCorp's utilization of an outside consultant, WSP Global, to evaluate wind, solar, and battery storage benefitted stakeholders.
- The final shortlist was reasonably aligned with the 2019 IRP preferred portfolio.

Q. Did the Oregon Commission acknowledge the shortlist?

A. Yes.[14] Acknowledgement means that the Oregon Commission found that the "final shortlist appears reasonable at the time of acknowledgment and was determined in a manner consistent with [Oregon's] competitive bidding rules."[15] The Oregon Commission noted that the final shortlist "is a reasonable capacity and energy blend, with diversity in contract structures (and therefore rate impact profiles), technology types, and geography."[16]

C. Price-Policy Assumptions

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis.

A. The economic analysis of the Transmission Projects includes five price-policy scenarios—MM, MN, HH, LN, and SCGHG. 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 net-power costs ("NPC") benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Transmission 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 2 summarizes the price-policy scenarios used to analyze the Transmission Projects.

[14] Docket No. UM 2059, Order No. 21-437 (Nov. 24, 2021).
[15] *Id.,* at 12.
[16] *Id.,* at 13.

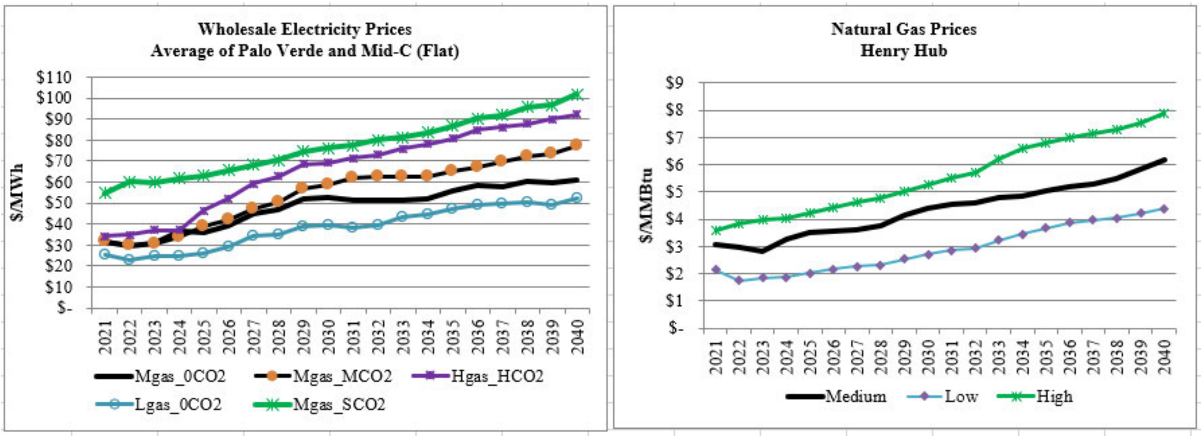
Table 2. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)	CO_2 Price Description
MM	$4.44	$9.93/ton starting 2025 rising to $57.94/ton in 2040
MN	$4.44	None
HH	$5.64	$22.57/ton starting 2025 rising to $102.48/ton in 2040
LN	$2.94	None
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 PacifiCorp prepared its modeling inputs for the 2021 IRP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (March 31, 2021, in this case). As such, these 36 months are market forwards as of March 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 an expert third-party, multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP4 ("Aurora"), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios.

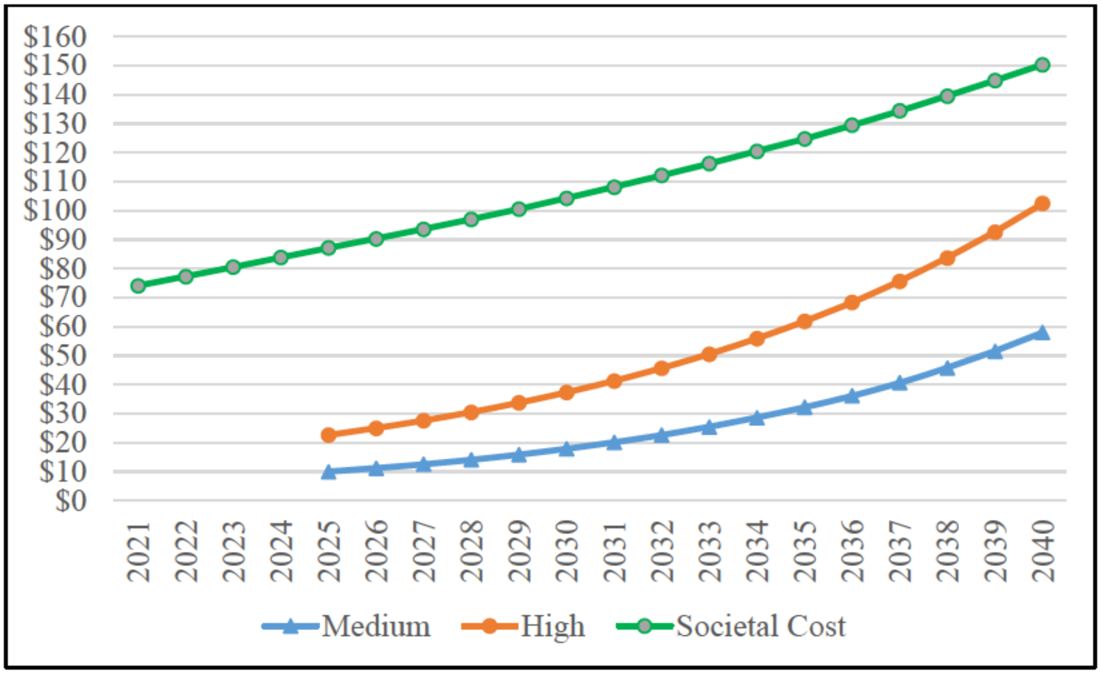
Figure 1. Natural Gas Price Assumptions



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

A. PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party, multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp also incorporated the social cost of greenhouse gas, which is assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the social cost of greenhouse gas is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Figure 2 shows the three non-zero CO_2 price assumptions used to analyze the Transmission Projects.

Figure 2. CO_2 Price Assumptions



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

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 the Transmission Projects. 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 risk is the Environmental Protection Agency's ("EPA") proposed OTR restricting nitrogen oxide ("NO_x") emissions from power plants and other industrial sources.[17] 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.

D. Modeling Methodology

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

A. PacifiCorp 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. Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the

[17] *See* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

Transmission Projects, and the other simulation excludes them. In addition, because wind bids selected from the 2020AS RFP located in eastern Wyoming cannot interconnect without the Transmission Projects, these wind resources are also eliminated from the simulation without the Transmission Projects. When the two simulations are compared, changes to system costs are attributable to the Transmission Projects and associated wind resources from the 2020AS RFP final shortlist.

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

Q. Are there any other costs that differ between the simulations with and without the Transmission Projects?

A. Yes. The simulation that excludes the Transmission Projects includes the cost of transmission upgrades necessary to accommodate PacifiCorp's obligation to provide 500 MW of firm PTP transmission service to a third-party customer. As explained in more detail by Mr. Vail, these transmission upgrade costs were included because, even conservatively ignoring all the executed interconnection service and transmission service contracts listing the Transmission Projects as prerequisites and focusing solely on the upgrades required to provide service under one transmission service contract, PacifiCorp assumed it would need to construct a 230-kV line by the end of 2024 at an estimated cost of approximately $1.4 billion.

Further, this $1.4 billion cost is the minimum cost for the alternative considering that it includes only the upgrades required to provide service under a single transmission service contract. Additional costs would be incurred to provide service under all interconnection service contracts listing the Transmission Projects as prerequisites. To provide service under all these contracts, it is likely the alternative would be to construct the Transmission Projects, which means that construction of these transmission investments are unavoidable given PacifiCorp's federal open access transmission tariff obligations to grant interconnection and transmission service requests.

Q. Please describe the modeling tool used to create the economic analysis of the Transmission Projects.

A. PacifiCorp uses the PLEXOS modeling system. The PLEXOS modeling system provides three platforms of the PLEXOS tool (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. The PLEXOS tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years. Portfolios from the LT model are informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk among five price-policy scenarios (MM, MN, HH, LN, and SCGHG). A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used to ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, resource portfolios (with and without the Transmission Projects and associated wind resources) were developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management ("DSM") alternatives within PacifiCorp's system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model.

The ST model begins with a portfolio from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour; and 2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of the Transmission Projects?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The LT model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource and transmission capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Transmission Projects. The ST and MT models provide additional granularity on how the Transmission Projects are projected to affect system operations while assessing stochastic risks. Together, the LT, MT, and ST models are best suited to perform a benefit analysis for the Transmission Projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the Transmission Projects?

A. Yes. The economic analysis also included one sensitivity that quantified how changes in new resource capital costs for the two BTA wind projects and capital cost assumptions for the Transmission Projects influenced projected customer benefits.

Q. Mr. Vail's testimony indicates that the Transmission Projects will enable up to 2,030 MW of new resources to interconnect in eastern Wyoming. Why does your analysis only account for 1,640 MW?

A. The economic analysis reasonably accounted for only those wind resources that were selected to the 2020AS RFP final shortlist.

Q. Does PacifiCorp assume that all the up-front capital costs of the Transmission Projects will be paid by its retail customers?

A. No. The cost of the Transmission Projects will be shared between PacifiCorp's retail and wholesale transmission customers. In my analyses, I assumed retail customers would pay 80 percent of the revenue requirement from the up-front capital cost for the Transmission Projects, after accounting for an assumed 20 percent revenue credit from the Company's transmission customers.

E. Price-Policy Scenario Results

Q. Please summarize the PVRR(d) results calculated from the PLEXOS model.

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario.

Table 3. PVRR(d) (Benefit)/Cost of the Transmission Projects ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($128)	($260)
LN	$755	$670
MN	$393	$289
HH	($932)	($1,100)
SCGHG	($2,568)	($2,819)

As shown above, system costs increase when the Transmission Projects are removed from the portfolio in the MM, HH, and SCGHG price-policy scenarios.

Conversely, costs decrease in the LN and MN price-policy scenarios. Without the Transmission Projects, emissions from PacifiCorp's generation resources increase considerably—ranging from 8.4 percent in the MN price-policy scenario to 17.8 percent in the SCGHG price-policy scenario. The LN and MN scenarios unrealistically fail to account for the risk that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions over the planning period. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building the Transmission Projects should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under the HH and SCGHG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios.

Considering that the removal of the Transmission Projects increases system costs among the MM, HH, and SCGHG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk (discussed further below), this analysis supports the necessity of the Transmission Projects and indicates that they are likely to result in robust customer benefits.

Q. Did you calculate how the PVRR(d) results presented above would change if you assumed the Transmission Projects would be required to provide service under all these interconnection and transmission service contracts?

A. Yes. This would increase the cost of the "alternative" to equal the cost of the Transmission Projects, which represents a $971 million increase in unavoidable capital relative to what is shown in the table above. This translates into $482 million on a

PVRR basis. Table 4 shows the PVRR(d) results with this level of unavoidable capital. When this higher cost is applied to the results, the MN price-policy scenario now shows there are significant customer benefits from the Transmission Projects.

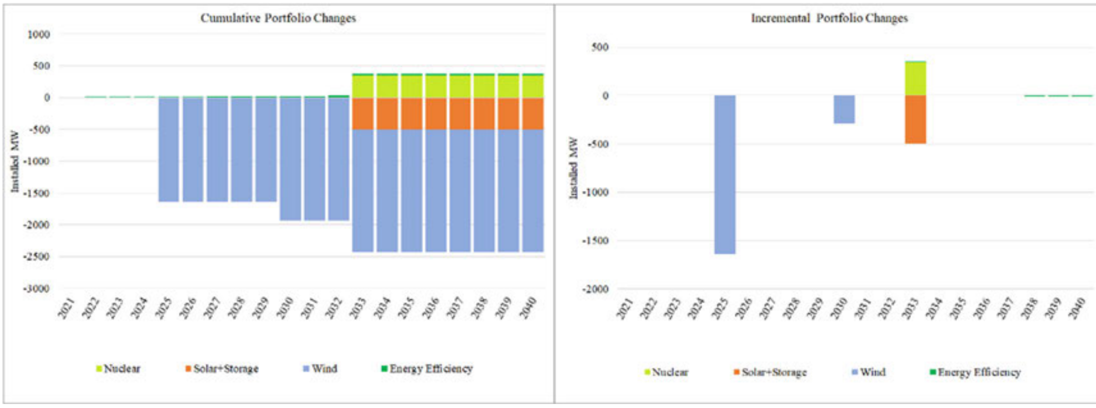
Table 4. PVRR(d) (Benefit)/Cost of the Transmission Projects Assuming the Transmission Projects are Unavoidable ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($610)	($742)
LN	$273	$188
MN	($90)	($194)
HH	($1,414)	($1,582)
SCGHG	($3,050)	($3,301)

Q. Please describe the impact of removing the Transmission Projects and associated wind resources from the 2021 IRP's preferred portfolio.

A. Figure 3 shows the cumulative (at left) and incremental (at right) portfolio changes when the Transmission Projects are eliminated under the MM price-policy scenario. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the Transmission Projects are eliminated. Without the Transmission Projects, the 1,640 MW of wind resources selected in the 2020AS RFP are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an advanced nuclear plant that displaces solar co-located with storage resources.

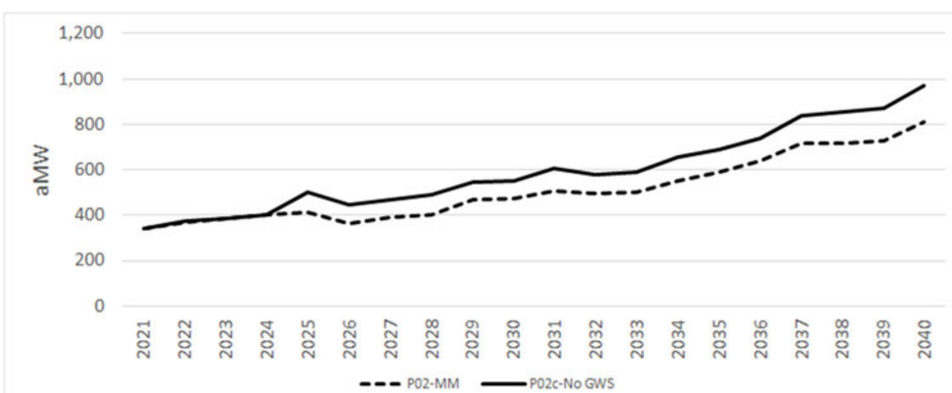
Figure 3. Changes in the Resource Portfolio without the Transmission Projects



Q. Does the removal of the Transmission Projects and associated wind resources increase the Company's reliance on market purchases?

A. Yes. Figure 4 shows how market purchases change when the Transmission Projects are removed from the portfolio under the MM price-policy scenario. With fewer resources, market purchases increase by nearly 20 percent on an annual basis. This creates higher risk as the Company is forced to rely on market purchases at a time when there are increasing resource adequacy concerns throughout the western interconnect. This increased market and reliability risk is not reflected in the PVRR(d) results.

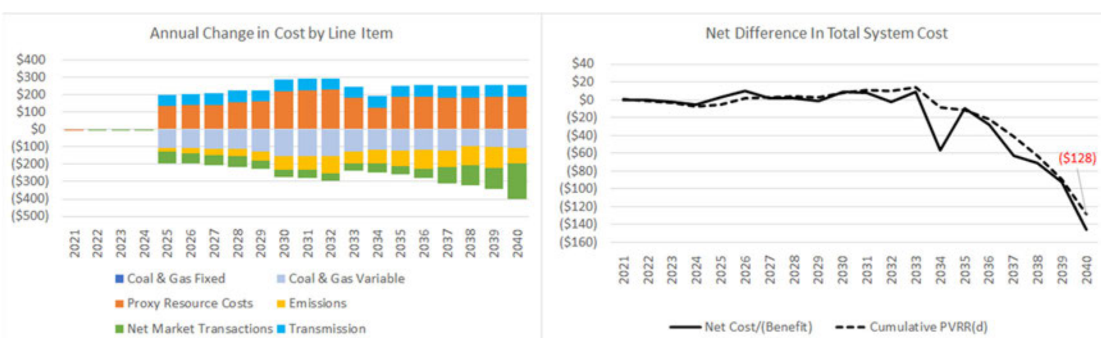
Figure 4. Changes in Market Purchases without the Transmission Projects



Q. How do system costs change with and without the Transmission Projects?

A. Figure 5 summarizes changes in system costs (conservatively assuming the cost for a 230-kV alternative is unavoidable), based on ST model results using MM price-policy assumptions, when the Transmission Projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the Transmission Projects is $128 million higher cost than the portfolio with the Transmission Projects. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the Transmission Projects is $260 million higher cost than the portfolio with the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 5. Increase/(Decrease) in System Costs when the Transmission Projects are Removed from the Portfolio



Q. Is there incremental customer upside to the PVRR(d) results?

A. Yes. The PVRR(d) results presented in Tables 3 and 4 do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by the Transmission Projects. Customer benefits for all price-policy scenarios would improve by approximately $42 million for every dollar assigned to the incremental RECs that will be generated through 2040. Beyond potential REC-revenue benefits, the economic analysis of the Transmission Projects does not reflect the reliability benefits that these investments will provide to the transmission system, which are described by Mr. Vail.

Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. The risk-adjusted PVRR(d) results show an increase in the benefits of the Transmission Projects when compared to the reported ST-model PVRR(d) results. This indicates that the Transmission Projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

F. Sensitivity Analysis Results

Q. Have you calculated how changes in the capital cost for the Transmission Projects might affect customer benefits?

A. Yes. A one percent increase in the initial capital costs associated with the Transmission Projects would reduce PVRR benefits by $4.8 million. This estimate conservatively assumes that there is no change in transmission costs that will be avoided with the construction of the Transmission Projects. In the MM price-policy scenario, capital costs for the Transmission Projects would need to increase by 54 percent to eliminate customer benefits on a risk-adjusted basis. This demonstrates that the projected customer benefits are robust to potential variations in capital costs for the Transmission Projects, particularly when considering that the cost estimates used in the economic analysis of the Transmission Projects reflect PacifiCorp's experience with the recent construction of Gateway West Segment D.2 and the associated 230-kV network upgrades reflecting current market conditions.

G. Post-Construction Economic Review

Q. Did you continue to revisit your economic analysis of the Transmission Projects after initiating construction?

A. Yes.

Q. Why did you continue to revisit your economic analysis?

A. After PacifiCorp provided its notice to proceed to begin constructing the Transmission Projects, the Company continued to negotiate contracts for the wind resources that are dependent on the Transmission Projects. During the pendency of those negotiations, there were two significant developments that affected the cost of the wind resources. Considering that the cost of the wind resources affects the economic analysis of the Transmission Projects, I continued to check that changes to costs did not erode customer benefits.

Q. Please describe the two developments that affected the cost of the wind resources dependent upon the Transmission Projects.

A. First, as the Company finalized contracts with resources selected to the 2020AS RFP final shortlist, national tariff policies, global supply-chain challenges, and inflationary pressures required that bidders secure higher prices than originally offered into the 2020AS RFP. Second, Congress passed the IRA that, among other things, provided an opportunity for the wind projects dependent upon the Transmission Projects to qualify for a 110 percent PTC, which is substantially higher than the 60 percent PTC assumed in my economic analysis that supported the Company's decision to begin constructing the Transmission Projects.

Q. How did you evaluate the impact of these developments on the economic analysis of the Transmission Projects?

A. As the Company finalized the wind resource contracts to capture price changes and new provisions related to the IRA, MM price-policy results were revisited so that we could understand how the economic analysis was being impacted. The updated analysis captured price changes in the contracts and incorporated updated energy values for projected wind energy using more current market price assumptions (i.e., June 2022).

Q. Did your post-construction economic review capture other updates?

A. Yes. Due to the price pressures I discussed above, some of the 2020AS RFP final shortlist bidders were unwilling to offer any form of price update. These projects were removed from consideration. While this did not include any of the wind projects dependent on the Transmission Projects, the removal of bids increases the overall need for new resources. The updated analysis also included any new contracts that were executed outside of the 2020AS RFP process and incorporated the most current load forecast, which was developed in May 2022. The updated analysis also accounted for the potential impact of the OTR.

Q. What did you find when you prepared this post-construction economic review of the Transmission Projects?

A. This on-going review continued to show that the Transmission Projects are expected to generate customer benefits. The last of these reviews, prepared in September 2022, reflected updated pricing for all wind resource PPAs dependent upon the Transmission Projects and showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario. This is similar to the comparable risk-adjusted customer benefits totaling $260 million from the economic analysis in place when the Company initiated construction of the Transmission Projects.

Q. Does this conclude your testimony for the Transmission Projects?

A. Yes.

IV. ROCK CREEK I WIND FACILITY

A. Need

Q. Does PacifiCorp have a need for Rock Creek I?

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. 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. Is Rock Creek I 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 190 MW from Rock Creek I.[18]

[18] 2021 IRP ,at Vol. I, Ch. 9.

Q. Does Rock Creek I rely on the Transmission Projects for interconnection?

A. Yes.

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

A. Rock Creek I is 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.

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

A. Acquiring Rock Creek I 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 earlier in my 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 Rock Creek I?

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, in particular, in the western half of Canada and the United States.[19]

Rock Creek I 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. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[20]

Q. Was Rock Creek I considered in the Company's 2021 IRP Update?

A. Yes. Rock Creek I was included in the IRP Update preferred portfolio.

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 Rock Creek I, the 2021 IRP Update's preferred portfolio shows generally lower market purchases in the first five years relative to the

[19] 2022 Summer Reliability Assessment, North American Electric Reliability Corporation (May 2022).
[20] PacifiCorp 2021 IRP Update (Mar. 31, 2022) (available here).

2021 IRP preferred portfolio.[21]

B. The 2020AS RFP

Q. Was Rock Creek I selected in the 2020AS RFP?

A. Yes. As stated above, the 2020AS RFP final shortlist includes six final shortlist bids representing over 1,600 MW of wind generation that require the Transmission Projects to interconnect to PacifiCorp's transmission system. These bids include Rock Creek I, which together with Rock Creek II are 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 Rock Creek?

A. Yes. Both Rock Creek I and Rock Creek II were bid into the 2020AS RFP by the same developer (Invenergy) and, as discussed by Mr. McGraw, the Company has engaged in BTA negotiations with Invenergy for both projects. Because Rock Creek I and II have the same counterparty and are being developed simultaneously subject to materially identical BTAs, the Company's economic analysis has largely analyzed the projects together.

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

[21] *Id.,* at Figure 1.11.

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 Rock Creek I costs 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 Rock Creek I have increased relative to the project's bid in the 2020AS RFP. The economic analysis described below is based on the up-to-date project costs.

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

A. Yes. PacifiCorp's original economic analysis in the 2020AS RFP assumed that Rock Creek I qualified for a 60 percent PTC through the first 10 years of operation. The economic analysis in this case, however, 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 Rock Creek I and II.

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

C. Modeling Assumptions

Q. Did the Company analyze Rock Creek I and Rock Creek II together?

A. Yes, for the most part. As stated above, there were two BTA wind facilities in the Company's final shortlist of projects: Rock Creek I and Rock Creek II. The second facility is a much larger wind facility, at 400 MW compared to Rock Creek I at 190 MW. In previous regulatory proceedings, the Company analyzed the wind projects together to determine whether acquiring the projects would provide net benefits to customers. This was reasonable, because the projects are co-located with each other and share the same modeling assumptions.

That is contrasted with this proceeding, where the Company is only requesting rate recovery of Rock Creek I, because Rock Creek II has an in-service date that falls outside the test period of this rate case. Nonetheless, several of the analyses below include combined results from both wind projects, as well as Rock Creek I specific analyses. This allows the Commission to examine both the additive benefits that will occur when wind projects are interconnected to PacifiCorp's system, but also the Rock Creek I specific customer benefits that inform the Company's revenue requirement in this proceeding.

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

A. The economic analysis of Rock Creek I included three price-policy scenarios—the MM, MN, and LN price-policy scenarios.[22] 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 net-power cost (NPC) benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with Rock Creek I. 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 5 summarizes the price-policy scenarios used to analyze Rock Creek I.

Table 5. Price-Policy Scenario Assumption Overview

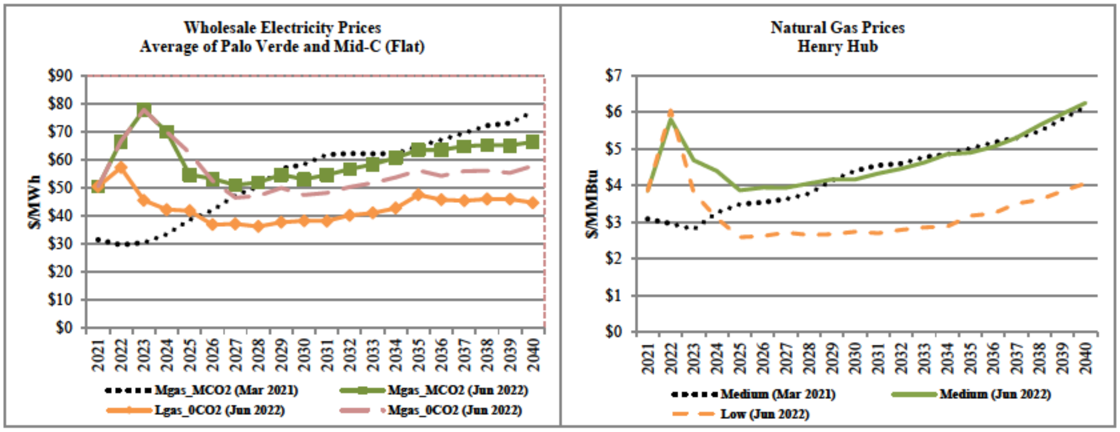
Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.52	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	$4.52	None
LN	$2.92	None
*Nominal levelized Henry Hub natural gas price from 2025 through		

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

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. Consistent with my Transmission Project testimony, the fundamentals portion of the natural gas OFPC reflects Aurora-forecasted prices. Figure 6 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios compared to the medium price used in the 2021 IRP forecast from March 2021. The electric prices comparison is also shown. The June 2022 price forecast reflects updates to natural gas price that is higher in the near term from recent market price trends. The updated gas prices also account for limitations in west coast states to add new natural gas.

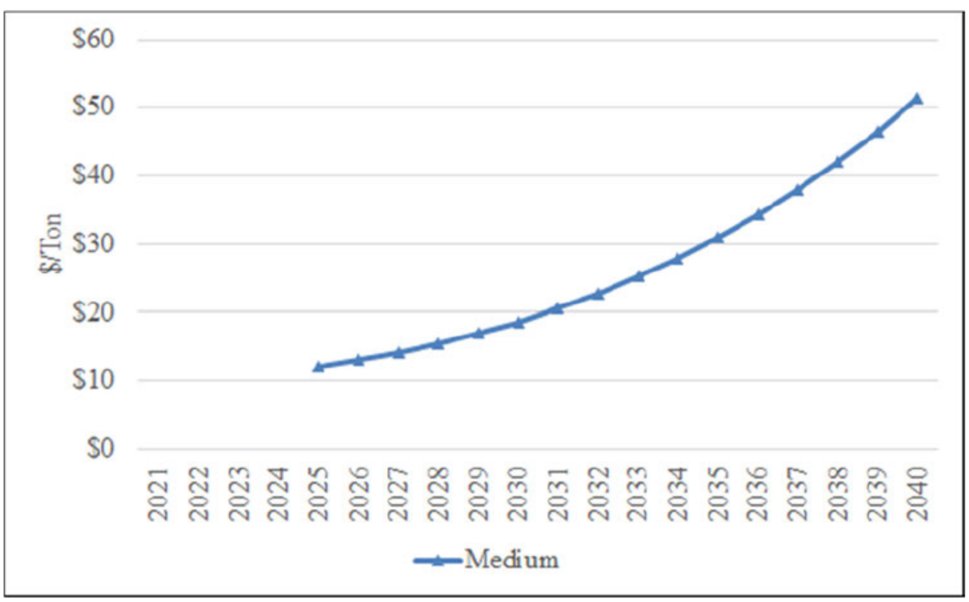
Figure 6. Nominal Electric and Natural Gas Price Assumptions



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, as shown in Figure 7.

Figure 7. CO_2 Price Assumptions



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

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 8 and 9 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 8. Forecasted Annual System Load

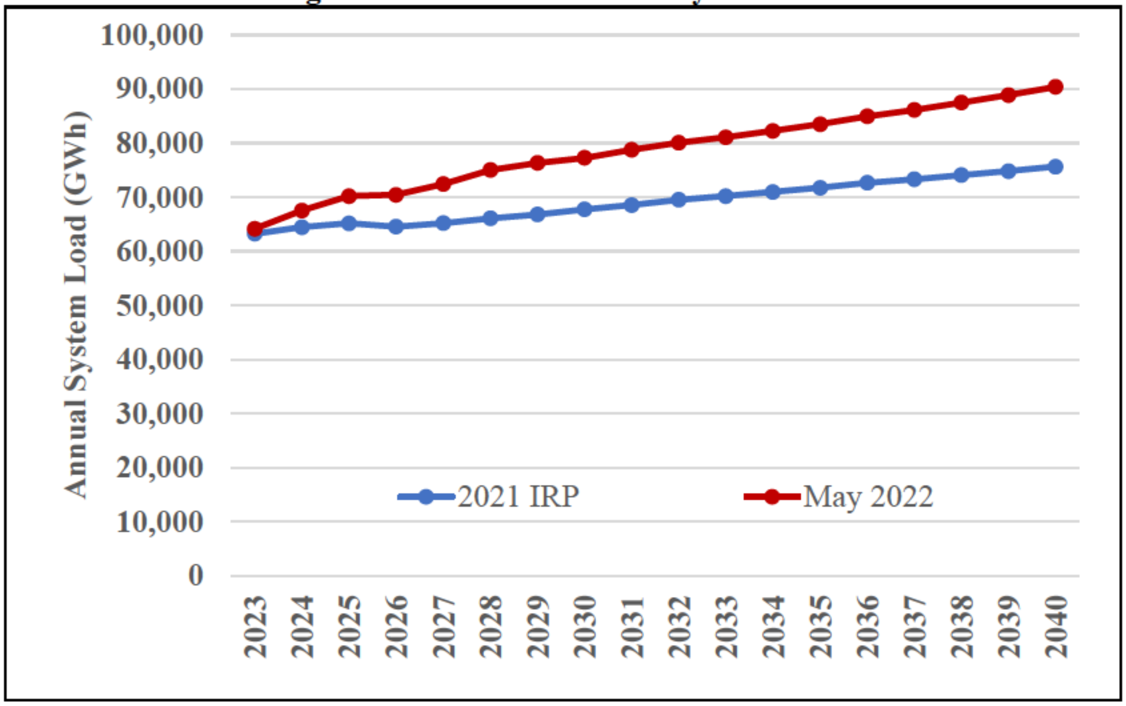
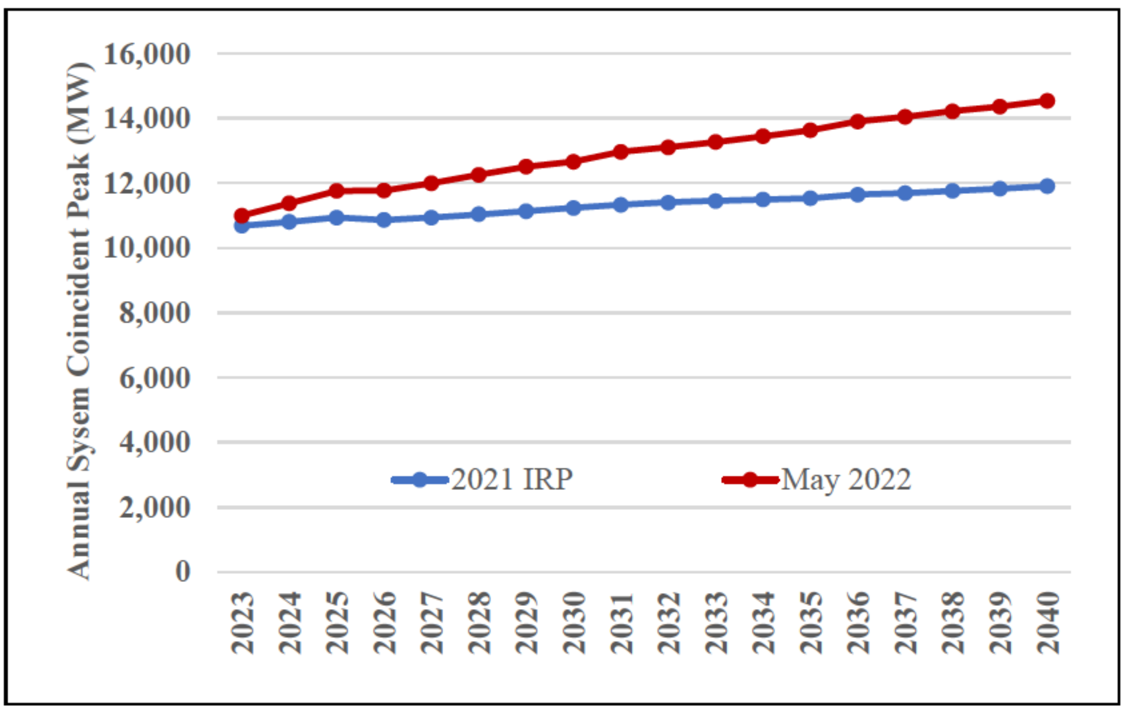


Figure 9. Forecasted Annual System Coincident Peak



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

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,[23] 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.[24] In order 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 states is quite limited. With that in mind, PacifiCorp's current planning assumes that it

[23] 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.

[24] 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.

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.[25]

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.

D. Modeling Methodology

Q. Please describe the modeling methodology PacifiCorp used in its analysis of the wind projects.

A. Consistent with my Transmission Project testimony, the Company calculated a system

[25] 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]

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 both Rock Creek I and Rock Creek II, 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 prior to passage of the IRA, and after to reflect the value of increased PTCs.

PacifiCorp also calculated a PVRR(d) based on one simulation that includes only Rock Creek I and compares it to a simulation that excludes both Rock Creek projects and one simulation that includes only Rock Creek II and compares it to a simulation that excludes both Rock Creek projects. In all studies, the Transmission Projects were assumed in-service in both scenarios with and without both projects 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. What portfolios did you analyze using the PLEXOS model in this case?

A. Portfolios were analyzed with and without both projects, with and without Rock Creek I, and with and without Rock Creek II, including certain results pre-IRA and post-IRA.

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.

E. Price-Policy Scenario Results

Q. What is the purpose of this sub-section?

A. I provide the results of my price-policy scenarios, including those preformed prior to passage of the IRA, and those performed after. All indicate strong customer benefits resulting from Rock Creek I, and those benefits only improve after factoring in impacts increased PTC benefits from the IRA.

Q. Please summarize the pre-IRA results for the simulations that focused on each Rock Creek project individually.

A. Tables 6 and 7 summarize the PVRR(d) results for each price-policy scenario for the scenarios that examined each of the Rock Creek projects prior to passage of the IRA.

Table 6. Pre-IRA (Benefit)/Cost of Rock Creek I ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	(15)	(20)
MN	(9)	(15)
LN	3	(2)

Table 7. Pre-IRA (Benefit)/Cost of Rock Creek II ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	(24)	(33)
MN	(14)	(24)
LN	8	(3)

Rock Creek II generally provides a larger benefit, because it is approximately twice the size of Rock Creek I. All the same, under the MM price-policy scenario, Rock Creek I lowers total system costs by $15 million, and adjusted for risk these benefits increase to a $20 million reduction in system costs. System benefits generally mirror the results seen in Table 6 when both projects were considered together, with a slight cost for Rock Creek I and Rock Creek II in the LN scenario prior to adjusting for risk and benefits in each of the other scenarios. Both projects, when evaluated individually, yield benefits on a risk-adjusted basis among all three price-policy scenarios.

Q. Why did PacifiCorp decide to update its economic analysis after passage of the IRA?

A. Based on existing law, PacifiCorp's economic analysis assumed that Rock Creek I qualified for 60 percent of available PTCs through the first 10 years of operation. After passage of the IRA, the Company understands that both Rock Creek projects qualify for 110 percent of available PTCs. This provides a significant increase to the economic benefits from the projects, and the Company's updated analysis reflects those benefits. The Company also updated its analysis to reflect current project costs.

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

A. Table 8 summarizes the PVRR(d) results for each price-policy scenario from the combined projects after passage of the IRA. [26]

[26] Modeling was initially based on an assumed start date of June 1, 2025 for Rock Creek II. The current expected start date is now September 1, 2025. The reported results have been adjusted to reflect the energy and production tax credit impacts of this change.

Table 8. Post-IRA (Benefit)/Cost of Both Wind Projects ($ million)

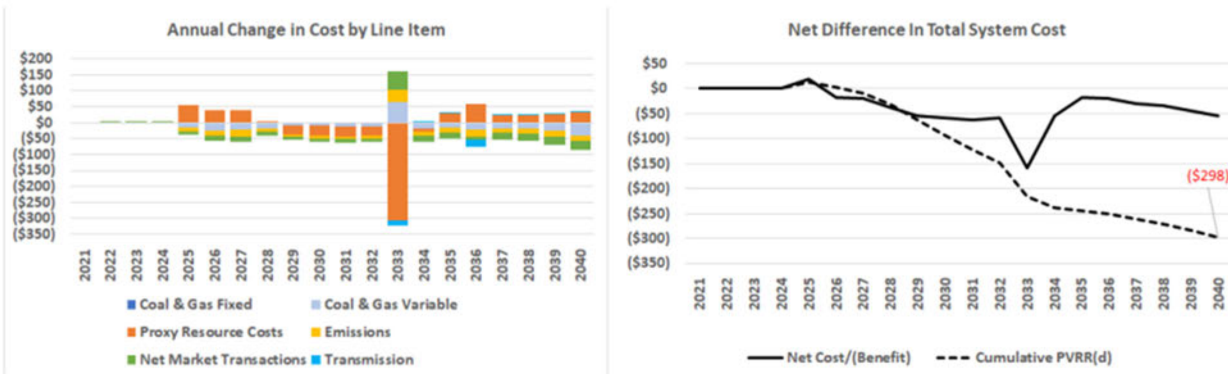
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	= (a) + (e)	= (b) + (e)
Price-Policy Scenario	**PVRR(d)**	**Risk-Adjusted PVRR(d)**	**110% PTC Update**	**Project Cost Update**	**Total Update**	**Updated PVRR(d)**	**Updated Risk-Adjusted PVRR(d)**
MM	(143)	(163)	(197)	42	(155)	(298)	(318)
MN	(33)	(51)	(194)	42	(151)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

As shown above, prior to adjusting for risk, system costs are now lower when the wind projects are included in the portfolio in all scenarios. When the risk adjustment is included, benefits from the wind projects increase. 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 system costs change post-IRA with and without both projects?

A. Figure 10 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when both projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio that includes both projects is $298 million lower cost than the portfolio without both.

Figure 10. Increase/(Decrease) in System Costs when both Projects are Removed from the Portfolio ($ millions) Medium Gas/Medium CO2



Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. For both projects, the risk-adjusted medium gas medium CO_2 PVRR(d) results show a benefit of $318 million, which is higher than the reported ST-model PVRR(d) results of $298 million prior to the risk adjustment. This indicates that the wind projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

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 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 11. As shown, allowance allocations could be significantly lower than what is assumed to be available in the current ST-model results, which would increase the value of generation from resources without emissions, such as Rock Creek I.

Confidential Figure 11. Forecasted OTR Allocation and Modeled Requirements

[redacted]

Q. Your updated economic analysis reflects higher project costs. Would the wind projects provide customer benefits even if the construction costs increase further?

A. Yes. For the wind 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 benefits under the MM price-policy scenario, project costs could increase by 35 percent. To negate the $202 million in risk-adjusted benefits under the MN price-policy scenario, project costs could increase by 22 percent.

F. Sensitivity Analysis Results

Q. Can RECs provide incremental customer upside?

A. Yes. The PVRR(d) results presented in Tables 6–8 did 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.

Q. Are there additional items that reflect the conservative nature of the Company's economic analysis?

A. Yes. The Company's current analyses understates 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 Rock Creek I. 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 Rock Creek I.

Q. Would Rock Creek I 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. Does this conclude your testimony for Rock Creek I?

A. Yes.

V. CONCLUSION

Q. Please summarize the conclusions of your testimony on the Transmission Projects.

A. PacifiCorp's analysis shows that the Transmission Projects are necessary and in the public interest. Under the MM price-policy scenario, the Transmission Projects produce significantly lower total system costs—ranging from $128 to $260 million when using the most conservating assumptions for avoided transmission and ranging from $610 million to $742 million when assuming the Transmission Projects are unavoidable. The Transmission Projects are also lower risk than alternative scenarios without the resources. Most notably, without the Transmission Projects and accompanying wind resources, the Company is forced to rely heavily on market purchases to serve load, which increases risk related to market volatility and creates reliability concerns given the region's well established resource adequacy concerns. By proactively constructing the Transmission Projects the Company can not only save customers money (as evidenced by the savings in the MM price-policy scenario) but also reduce customer risk, which is a non-quantifiable benefit that strongly favors the Transmission Projects. The updated economic analysis of the Transmission Projects demonstrates that net benefits more than outweigh net project costs.

Q. Please summarize the conclusions of your Rock Creek I testimony.

A. PacifiCorp's analysis shows that Rock Creek I is necessary and in the public interest. The Company has a substantial near-term need for resources at a time when the entire region is expected to be resource deficient. Rock Creek I is a cost-effective way to meet that identified resource need. Prior to passage of the IRA, benefits for Rock Creek I ranged from $15 to $20 million when using medium natural gas and medium CO_2 assumptions. These benefits increase to $298 to $318 million, respectively, when considering both (a) the additive benefits of Rock Creek II, a co-located sister-facility not included in this proceeding, but that was analyzed to provide a wholistic perspective of the benefits that Rock Creek I will provide; and (b) significantly increased benefits in PTCs that result from the IRA. Conservatively, these benefits do not assign any value to the RECs that will be generated by Rock Creek I.

Notably, without Rock Creek I the Company is forced to rely more heavily on market purchases to serve load, which increases risk related to market volatility and creates reliability concerns given the region's well established resource adequacy concerns. Rock Creek I also provides flexibility in meeting the EPA's proposed OTR.

Q. What do you recommend to the Commission?

A. As supported by PacifiCorp's economic analysis, I recommend that the Commission determine that PacifiCorp's decisions to invest in the Transmission Projects and Rock Creek I are prudent and reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM	)	DOCKET NO. 20000-___-ER-23 (RECORD NO. _____)

AFFIDAVIT, OATH AND VERIFICATION

Rick T. Link (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Senior Vice President, Resource Planning & Optimization, for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Senior Vice President, Resource Planning & Optimization.

Further Affiant Sayeth Not.

Dated this 27 day of February 2023

Rick T. Link
Senior Vice President, Resource
Planning & Optimization

STATE OF Oregon)
) SS:
COUNTY OF Multnomah)

The foregoing was acknowledged before me by Rick T. Link on this 27 day of February, 2023. Witness my hand and official seal.

Notary Public

My Commission Expires: 9/6/2025

OFFICIAL STAMP
KELLY ANN WIGGINS
NOTARY PUBLIC - OREGON
COMMISSION NO. 1015825
MY COMMISSION EXPIRES SEPTEMBER 06, 2025