Application No. 22-05-___
Exhibit PAC/400
Witness: Shayleah J. LaBray

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Direct Testimony of Shayleah J. LaBray

Repowering, 2021 Integrated Resource Plan, Coal Retirement Plans, Load Forecast

May 2022

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Shayleah J. LaBray. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource Planning and Acquisitions.

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in 2001 and assumed the responsibilities of my current position in 2021. Over this period, I held several analytical and leadership positions within the Company. I have been involved in the integrated resource planning process at PacifiCorp since 2016. Before taking on the responsibilities of my current role, I held analytical and leadership roles overseeing the Company's transmission annual formula rate and managing transmission contracts, state regulatory affairs, and developing customer service support systems. I graduated from Robert D. Clark Honors College at the University of Oregon in 2000 and received a Bachelor of Science degree in Business Administration.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for aspects of PacifiCorp's 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 general rate case application, I oversee the significant planning, analysis, and outreach processes that are used to develop PacifiCorp's IRP, and the economic analysis that helps guide the Company's resource acquisitions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in California and Utah.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony provides information as requested by the California Public Utilities Commission's (Commission) directive from the Company's 2019 general rate case (2019 Rate Case) to provide information on "its retirement plans for all coal facilities serving California customers, and any associated request for accelerated depreciation, consistent with its Integrated Resource Plan filings."[1] Additionally, my testimony presents PacifiCorp's load forecast used for this filing, also consistent with the Commission's directive from the Company's 2019 Rate Case. Finally, my testimony explains the economic analysis that was performed to support PacifiCorp's decision to repower the Foote Creek II-IV wind facilities in Wyoming.

Q. Please summarize your testimony.

A. My testimony explains the significant analysis that occurred in PacifiCorp's 2021 IRP process to arrive at the preferred portfolio. As part of that preferred portfolio, PacifiCorp revised the retirement dates for units at the Hayden, Craig, and Colstrip plants, while also recommending the conversion to natural gas of two units at the Jim Bridger plant. Based on the analysis of multiple portfolios, PacifiCorp determined the preferred portfolio which supports these retirement dates for the coal units as the least-cost, least-risk outcome for PacifiCorp's customers.

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[1] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019,* A.18-04-002, D.20-02-025 at 73 (Feb. 18, 2020).

Additionally, PacifiCorp has a thorough process that was used to develop a prudent and appropriate load forecast that was used by the Company in this proceeding. Finally, the economic analysis of Foote Creek II-IV shows that the acquisition and repowering of these wind facilities provides benefits to customers.

III. PACIFICORP'S INTEGRATED RESOURCE PLANNING

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

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk, which presents the Company's plans to provide reliable and reasonably priced service to its customers. The primary objective of the IRP is to identify the least-cost, least-risk portfolio of resources to serve customers in the future. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The Company completes an IRP cycle every two years (odd-numbered years), which includes preparation of a full IRP every two years and preparation of an update to the full IRP in the off years (even-numbered years). The Company submits both its IRP and IRP Update to each of the six regulatory commissions in the states where the Company provides retail service, including California,[2] as discussed further below.

[2] *See Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes*, R.20-05-003, Integrated Resource Plan of PacifiCorp (U 901-E) for 2019-2020 (May 7, 2020); S*ee also Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard*, R.18-07-003 (PacifiCorp has filed various supplements and updates to its IRP from 2018 to 2021 within this docket).

Each IRP is developed through an open, transparent and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process which typically spans at least a full year prior to the release of a full IRP, PacifiCorp holds regular meetings with stakeholders to solicit feedback on the Company's planning assumptions, methodologies and model results.

Q. Please explain how California has treated the Company's IRP filings.

A. PacifiCorp files its IRP in California in two separate proceedings. First, it is filed to meet California's requirements for a renewable portfolio standard (RPS) procurement plan. Second, it is filed to meet California's requirement for load-serving entities to prepare an IRP.

California's RPS procurement requirements allow multi-jurisdictional utilities like PacifiCorp to use an IRP prepared for regulatory agencies in other states to satisfy California's annual requirement to file an RPS procurement plan, as long as the IRP complies with the requirements specified in California Public Utilities Code § 399.17(d). As required by Decision (D.) 08-05-029, PacifiCorp files its IRP in Rulemaking (R.) 06-05-027 or its successor proceeding at the same time it files with the jurisdictions requiring the IRP. To fulfill this requirement, an 'IRP On-Year Supplement is filed within 30 days of filing the full IRP in the Company's other jurisdictions.' In accordance with D.11-04-030, PacifiCorp files an 'IRP Off-Year supplement on July 15 in years in which it does not file an IRP in lieu of an RPS procurement plan.' PacifiCorp's most recent filing was its On-Year IRP Supplement on October 1, 2021, in R.18-07-003.[3]

In Rulemaking 16-02-007, the Commission developed an IRP process for California. In February 2018, the Commission issued D. 18-02-018 which set the requirements for load-serving entities in California to file an IRP. The decision allows PacifiCorp to file an IRP submitted to another public regulatory entity within the previous calendar year along with an explanation of how it has considered disadvantaged communities, referred to as an Alternate IRP. PacifiCorp filed its Alternate IRP in California on September 1, 2021.[4]

Q. Does PacifiCorp analyze the cost effectiveness of continued operation of its coal fleet in its IRP?

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

Q. Has the Company's approach to analyzing its coal resources evolved over the last several IRPs / respond to stakeholder feedback and changes in energy markets, policies, and regulations?

A. Yes. The Company's planning process has become more sophisticated over time to

[3] In Decision 22-01-004 issued on January 13, 2022, the Commission accepted and deemed final, PacifiCorp's 2021 On-Year Supplement (RPS Procurement Plan).
[4] *Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Process*, R. 20-05-003, D.22-02-004 (Feb. 10, 2022); PacifiCorp's IRP is available at https://www.pacificorp.com/energy/integrated-resource-plan.html.

respond to stakeholder feedback and increasing complexities presented by changing energy markets, including movement in wholesale power and natural gas prices and the declining cost of renewable energy resources; the proliferation of clean energy policies, including state laws promoting renewable energy, controlling energy emissions, and promoting energy efficiency; and the application of environmental regulations, especially those designed to regulate clean air and greenhouse gas (GHG) emissions.

IV. PACIFICORP'S COAL RETIREMENT PLANS

Q. Please describe the Commission's directive to include information on retirement plans for all coal facilities serving California customers.

A. In PacifiCorp's last general rate case, the Commission directed PacifiCorp to provide information on "its retirement plans for all coal facilities serving California customers, and any associated request for accelerated depreciation, consistent with its Integrated Resource Plan filings."[5] In July of 2021, the Commission extended the deadline for making this filing and further detailed that "[t]he Commission can evaluate PacifiCorp's coal facility retirement plans in its 2023 general rate case more efficiently after PacifiCorp's plans are updated with information provided by PacifiCorp's 2021 Integrated Resource Plan[.]"[6]

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[5] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A. 18-04-002, D. 20-02-025 at 73 (Feb. 18, 2020).
[6] *In the Matter of the Application of PacifiCorp (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, A. 18-04-002, D. 21-07-012 at 5 (Jul. 21, 2021).

Q. Has PacifiCorp's 2021 IRP provided updated coal facility retirement dates in the preferred portfolio?

A. Yes; the current coal retirement dates under the 2021 IRP preferred portfolio are:

- 2023 = Jim Bridger Units 1-2
- 2025 = Naughton Units 1-2
- 2025 = Craig Unit 1
- 2025 = Colstrip Units 3-4
- 2027 = Dave Johnston Units 1-4
- 2027 = Hayden Unit 2
- 2028 = Craig Unit 2
- 2028 = Hayden Unit 1
- 2036 = Huntington Units 1-2
- 2037 = Jim Bridger Units 3-4
- 2039 = Wyodak
- 2042 = Hunter Units 1-3

Q. Please describe the changes in retirement dates that have occurred in the preferred portfolio since the 2019 IRP.

A. As noted above, Jim Bridger Units 1 and 2 are now scheduled to be retired in 2023 and converted to natural gas in 2024, retirement of Colstrip Units 3 and 4 has accelerated to 2025 from 2027, retirement of Hayden Unit 2 has accelerated to 2027 from 2030, retirement of Hayden Unit 1 has accelerated to 2028 from 2030, and retirement of Craig Unit 2 has moved from 2026 to 2028.

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

A. In the 2021 IRP, PacifiCorp incorporated a new and more advanced optimization modeling system called Plexos. The Plexos modeling system provides three platforms (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon.

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 for 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 (Medium Gas Price/Medium CO_2 Price ("MM"), Medium Gas Price/No CO_2 Price ("MN"), High Gas Price/High CO_2 Price ("HH"), Low-Gas Price/No CO_2 Price("LN"), and Social Cost of Greenhouse Gases ("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.[7]

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used the ST model to evaluate each portfolio to establish system costs over the 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value

[7] A more detailed description of this methodology is available in Chapter 8 of PacifiCorp's 2021 IRP.

outcomes as well as a present value revenue requirement (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?

A. In the first step, resource portfolios 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 transmission 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 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 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 were 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 were used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

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 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 identify whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Can you identify coal units for which the retirement date is driven by environmental requirements in the 2021 IRP?

A. Yes; the retirement dates for Craig Unit 2, Hayden Units 1 and 2, and Naughton Units 1 and 2 are being driven by environmental requirements and are discussed in the testimony of Company witness James Owen, Exhibit PAC/500.

Q. Please explain the customer benefits from the conversion of Jim Bridger Units 1 and 2 to natural gas as identified in the 2021 IRP?

A. As described in further detail below, the preferred portfolio identified the conversion of Jim Bridger Units 1 and 2 to be part of the least-cost, least-risk preferred portfolio.

Q. Please explain the proposed retirement date for Colstrip units 3 and 4.

A. The 2021 IRP preferred portfolio accelerates the retirement of Colstrip Units 3 and 4 to 2025 from 2027 in the 2019 IRP. Thus, PacifiCorp's 2021 IRP Action Plan includes Action Plan Item 1(a) to work closely with co-owners of Colstrip Units 3 and 4 to seek the most cost-effective path forward toward the target retirement date of December 31, 2025.

Q. What portfolios were evaluated leading to the selection of the preferred portfolio?

A. In the 2021 IRP, there were two types of portfolios developed in the process of selecting a least-cost, least-risk preferred portfolio of resources. These two types were identified as "initial" portfolios and "variant" portfolios. Both are summarized below and described in further detail in Chapter 9 – Modeling and Portfolio Selection Results of the 2021 IRP.

Q. Please summarize the initial portfolios used to arrive at the preferred portfolio.

A. Initial portfolios explored variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or carbon capture utilization and sequestration (CCUS) retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing. This includes a fully optimized view of potential retirements (a portfolio named P02), a partially optimized view of early retirements that requires all coal units to be retired by 2030 (a portfolio named P03), fixed retirements based on end-of-life operating assumptions (a portfolio named BAU1) and forced retirements consistent with the 2019 IRP preferred portfolio (a portfolio named BAU2).

Tables 1 through 5 present cost and risk results for the initial portfolios across the five price-policy scenarios, including the deterministic PVRR, the risk-adjusted PVRR, the amount of energy not served (ENS) as a percentage of load, and total CO_2 emissions.

As shown in Table 1, under the MM price-policy scenario, P02 outperforms other portfolios on a deterministic PVRR, risk-adjusted PVRR, and ENS basis. While P02 has higher cumulative CO_2 emissions, P03 has a risk-adjusted cost that is $1.7 billion higher than P02. Emissions levels are similar among the P02, BAU1, and BAU2 portfolios.

Table 1 – Initial Portfolios Cost and Risk Results Summary (Medium Gas/Medium CO_2)

	Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MM	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	26,179	$0	1	0.0049%	0.00000%	1	398,953	97,568	4
P03	27,876	$1,696	4	0.0051%	0.00021%	2	301,385	0	1
BAU1	27,200	$1,021	3	0.0051%	0.00021%	3	395,123	93,738	3
BAU2	27,054	$875	2	0.0053%	0.00037%	4	391,900	90,515	2

As shown in Table 2, in the LN price-policy scenario, P02 outperforms other cases on cost and ENS and has comparable emissions to BAU1 and BAU2. P02 cumulative CO_2 emissions are higher than in P03, driven by P03 retirement assumptions of retiring all coal by 2030, which has a risk-adjusted cost that is $2.5 billion higher than P02. Emissions levels are similar among the P02, BAU1, and BAU2 portfolios.

Table 2 – Initial Portfolios Cost and Risk Results Summary (Low Gas/No CO_2)

Case - LN	Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	22,252	$0	1	0.0053%	$0	1	472,867	172,908	4
P03	24,772	$2,520	4	0.0055%	$0	2	299,959	0	1
BAU1	22,663	$411	2	0.0058%	$0	4	447,378	147,419	2
BAU2	22,735	$483	3	0.0057%	$0	3	466,064	166,105	3

As shown in Table 3, in the MN price-policy scenario, P02 outperforms other cases on costs and ENS and has comparable emissions to BAU1 and BAU2. P02 cumulative CO_2 emissions are higher than in P03, driven by P03 retirement assumptions of retiring all coal by 2030, which has a risk-adjusted cost that is $3.5 billion higher than P02.

Table 3 – Initial Portfolios Cost and Risk Results Summary (Medium Gas/No CO_2)

Case - MN	Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	22,256	$0	1	0.0049%	$0	1	540,688	224,270	4
P03	25,780	$3,523	4	0.0053%	$0	3	316,418	0	1
BAU1	22,677	$420	2	0.0052%	$0	2	517,882	201,464	2
BAU2	22,702	$445	3	0.0055%	$0	4	537,670	221,252	3

As shown in Table 4, in the HH price-policy scenario, P02 outperforms other cases on costs and ENS and has comparable emissions to P03, the case with lowest emissions, which has a risk-adjusted cost that is $1.0 billion higher than P02.

Table 4 – Initial Portfolios Cost and Risk Results Summary (High Gas/High CO_2)

Case - HH	Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	27,993	$0	1	0.0056%	$0	1	283,845	5,527	2
P03	29,030	$1,037	2	0.0059%	$0	3	278,317	0	1
BAU1	29,804	$1,810	4	0.0056%	$0	2	365,205	86,888	4
BAU2	29,384	$1,391	3	0.0060%	$0	4	363,367	85,050	3

In the SCGHG, P02 outperforms other cases on cost (except for P03), outperforms P03 and BAU2 on ENS, and ties BAU1 on ENS. P02 emissions are comparable to P03 emissions, the case with lowest emissions. P03 retires all coal by 2030 and has a risk-adjusted cost that is $178 million lower than P02.

Table 5 – Initial Portfolios Cost and Risk Results Summary (Medium Gas/Social Cost and Greenhouse Gas)

Case - SCGHG	Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	39,318	$178	2	0.0068%	$0	1	184,121	13,417	2
P03	39,140	$0	1	0.0110%	$0	3	170,704	0	1
BAU1	41,421	$2,281	4	0.0102%	$0	2	214,365	43,662	4
BAU2	41,224	$2,084	3	0.0137%	$0	4	209,299	38,595	3

Based on these findings, PacifiCorp identified P02-MM as the top-performing portfolio at this stage of the portfolio-development process. PacifiCorp then developed and analyzed additional portfolios as variants of P02-MM, as described below.

Q. Please summarize the variant portfolios evaluated to arrive at the preferred portfolio.

A. Eight portfolios were developed as variants of the top-performing P02-MM portfolio. For each of these variants, the cost and risk impacts of alternative resource decisions, relative to those included in the P02-MM portfolios, were quantified. For each variant, the cost and risk implications of specific resource outcomes were tested by either eliminating those resources from consideration or by forcing alternative resource decisions. These variants were then compared to the cost and risk metrics of the P02-MM portfolio to quantify the customer benefits of each major resource included in the P02-MM portfolio. The P02-MM variant portfolios are summarized in Table 6.

Table 6 – Variant Portfolios

Case	Description
P02a – JB1-2 No GC	Excludes gas conversion of Jim Bridger Units 1 and 2
P02b – No B2H	Excludes Boardman-to-Hemingway transmission segment
P02c – No GWS	Excludes the Energy Gateway South transmission segment
P02d – No RFP	Excludes 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment
P02e – No Nuc	Excludes the Natrium™ advanced nuclear demonstration project
P02f – No Nau 25	Excludes the early retirement of Naughton Units 1 and 2
P02g – CCUS	Includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4 in response to Wyoming House Bill 200
P02h – JB 3-4 Retire	Includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback

Q. What was the conclusion of the initial and variant portfolio analysis?

A. The P02-MM portfolio remained the top performing portfolio, on a cost and risk basis, among the P02-MM variant portfolios.

V. LOAD FORECAST

Q. Please summarize your testimony on PacifiCorp's sales and load forecast.

A. I provide PacifiCorp's forecasts of the number of customers, kilowatt-hour (kWh) sales at the meter (sales), system loads and system peak loads at the system input level (loads), and number of bills by rate schedule for the 12-month period ending December 31, 2023. PacifiCorp's load forecast has been updated with the most recent information available and includes certain changes in methodology to more accurately forecast load.

Q. When did the Company prepare the sales and load forecast used in this filing?

A. The sales and load forecast used in this filing was completed in May 2021. The May 2021 sales and load forecast is the most recent forecast of sales and loads prepared by the Company.

Q. How did the Company use the May 2021 sales and load forecast in this filing?

A. The May 2021 load forecast was used by Company witness Steven R. McDougal, Exhibit PAC/900 to calculate the inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by Company witnesses André T. Lipinski, Exhibit PAC/1000, and Robert M. Meredith, Exhibit PAC/1100, to allocate costs between customer classes and to design rates that correctly reflect the cost of service.

Q. Please provide a general overview of the Company's sales and load forecast methodology.

A. The Company's methodology consists of first developing a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, meaning kWh sales levels are grossed-up to a generation or "input" level. The monthly loads are then spread to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

Q. Please provide a summary of the forecasted energy sales for 2023.

A. Table 7 provides the forecasted energy sales for the 12-month period ending December 31, 2023.

Table 7 – Test Period Sales Forecast (MWh)

2023 Rate Case (CY 2023)		
	Total Company	**California**
Residential	**17,109,240**	**381,987**
Commercial	**20,419,167**	**236,254**
Industrial	**18,619,291**	**52,810**
Irrigation	**1,475,938**	**91,001**
Lighting	**100,089**	**1,323**
Total	**57,723,723**	**763,375**

A. Comparisons to Prior Sales Forecasts

Q. How does the total-Company sales forecast for 2023 compare to the sales forecast used in the 2019 Rate Case?

A. As shown in Table 8, total-Company 2023 forecast sales are 6.4 percent higher than 2019 forecast sales used in the 2019 Rate Case. The difference in the forecasts is attributable to an increase in residential, commercial, and irrigation load. The growth in the residential class is attributable to strong historical class sales over recent years, while the growth in the commercial class is related to data centers. The industrial class decrease in the forecast is primarily attributable to a decline in commodity prices in 2020.

Table 8 – Test Period Sales Forecast (MWh)

	2019 Rate Case CY 2019	2023 Rate Case CY 2023	Percentage Change
Residential	15,635,103	17,109,240	9.4%
Commercial	18,136,363	20,419,167	12.6%
Industrial	18,878,955	18,619,291	-1.4%
Irrigation	1,473,877	1,475,938	0.1%
Lighting	142,127	100,089	-29.6%
Total	54,266,425	57,723,723	6.4%

Q. How does the California sales forecast for 2023 compare to the sales forecast for the 2019 Rate Case?

A. As shown in Table 9, the 2023 California sales forecast has increased by approximately 2.1 percent from the 2019 sales forecast used in the 2019 Rate Case. The increase in residential class sales is driven by both customer growth and an increase in use-per-customer. The commercial class increase is driven by the most current economic outlook for the class. The decline in the industrial load reflects the continuing decline in industrial sales in the Company's California service territory.

Table 9 – California Sales Comparison (MWh)

	2019 Rate Case CY 2019	2023 Rate Case CY 2023	Percentage Change
Residential	371,105	381,987	2.9%
Commercial	221,197	236,254	6.8%
Industrial	57,124	52,810	-7.6%
Irrigation	95,996	91,001	-5.2%
Lighting	2,038	1,323	-35.1%
Total	747,460	763,375	2.1%

B. Forecast Methodology

Q. What aspects of the sales and load forecast methodology do you address?

A. First, I describe the data and assumptions used to produce the sales and load forecasts. Second, I describe the forecasting approach used to develop customer forecasts for all classes. Third, I describe the forecasting approach for developing monthly sales for the residential, commercial, industrial, irrigation, and lighting customer classes. Fourth, I describe how the hourly load forecast is developed. Fifth, I describe how the forecasts by rate schedule for sales and number of bills are developed.

C. Summary of Forecast Data and Assumptions

Q. Please summarize the major inputs used to produce the 2023 forecast.

A.
1. For California, the residential, commercial, irrigation and lighting classes use a historical data period of January 2000 through February 2021. The historical data period used to develop the industrial monthly sales is from January 2003 through February 2021.
2. The historical data period used to develop the monthly peak forecasts is from February 2003 through December 2020.
3. The Company used the economic drivers for each of the Company's jurisdictions using IHS Markit data released in March 2021.
4. The Company used the forecast of individual industrial and commercial customer usage based on the best information available as of February 2021.
5. The time period used to calculate normal weather was defined as the 20-year time period of 2001 through 2020.

6. The Company's line loss calculation is based on the five-year period ending December 2020.
7. The data used to develop temperature splines was based on customer class hourly data (October 2015 through September 2020).
8. The Company used the residential use-per-customer model with appliance saturation and efficiency results released in July 2020.

D. Customer Forecast Methodology

Q. How are the forecasts for number of customers developed?

A. For the residential class, the Company forecasts the number of customers using IHS Markit's forecast of number of households or population as the major driver. The Company uses a differenced model approach in the development of the residential customer forecast. For the commercial class, the Company forecasts the number of customers using households or population as the major economic driver. For the industrial, irrigation and street lighting classes, the customer forecasts are relatively static and developed using time series or regression models without any economic drivers.

E. Monthly Sales Forecast Methodology

Q. What methodology does the Company use to forecast residential class sales?

A. The Company develops the residential sales forecasts as a product of two separate forecasts: (1) the number of customers – as described above; and (2) sales per customer. The Company models sales-per-customer for the residential class through a Statistically Adjusted End-Use (SAE) model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling-related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income, and historical energy price. The Company develops both a transportation and building electrification forecast, which are incorporated as post-model adjustments to the residential sales forecasts.

Q. What methodology does the Company use to forecast commercial class sales?

A. For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment or non-farm employment, as the economic drivers, in addition to weather-related variables. For a small number of data center customers, the largest on the Company's system, the Company individually forecasts these customers based on input from the customer and information provided by the Company's regional business managers (RBMs). The Company develops both a transportation and building electrification forecast, which are incorporated as post-model adjustments to the commercial sales forecasts.

Q. How does the Company forecast sales for industrial customer class?

A. Most industrial customers are modeled using regression analysis with manufacturing employment or an industrial production index as the major economic driver. Also, similar to how the Company forecasts individual data center customers, for a small number of industrial customers, the largest on the Company's system, the Company individually forecasts these customers based on input from the customer and information provided by the RBMs.

Q. What methodology does the Company use for the irrigation and lighting sales forecasts?

A. For the irrigation class, the Company forecasts sales using regression analysis techniques based on historical sales volumes and weather-related variables. Monthly sales for lighting are forecast using regression analysis techniques based on historical sales volumes and a light-emitting diodes (LED) lighting adoption curve.

F. Hourly Load Forecast

Q. Please outline how the hourly load forecast is developed.

A. After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps.

First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. These weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the peak. This forecast is based on average monthly historical peak-producing weather for the 20-year period 2001 through 2020.

Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

G. Forecasts by Rate Schedule

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, Company witness Mr. Lipinski requires two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers by rate schedule must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. The Company develops this forecast in two steps. First, the Company forecasts test year sales by rate schedule. Then the Company proportionally adjusts the rate schedule sales forecasts so that the total across the rate schedules matches the customer class forecast.

Q. How does the Company forecast the number of bills for each rate schedule?

A. The forecast of the number of bills for each rate schedule follows the same process as the sales forecast for each rate schedule. First, the Company forecasts the number of bills by class and by rate schedule. Then, the Company proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills across the rate schedules matches the customer class forecasted number of bills.

VI. REPOWERING OF FOOTE CREEK II-IV

Q. Please describe the repowering of the Foote Creek II-IV facilities.

A. As described in the testimony of Company witness Timothy J. Hemstreet, Exhibit PAC/700, PacifiCorp is acquiring and repowering these facilities. The repowering of the Foote Creek II-IV facilities involves installing approximately 11 modern Wind Turbine Generators, which would increase the power generation from and extend the lives of the facilities.

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

A. Yes. The Foote Creek II-IV acquisition and repowering project was included as part of the least-cost, least-risk 2021 IRP preferred portfolio.

Q. Please describe key factors supporting the inclusion of the Foote Creek II-IV wind projects in PacifiCorp's 2021 IRP preferred portfolio.

A. The project is anticipated to be fully online and serving customers in December 2023. This timing enables Foote Creek II-IV to deliver needed energy and capacity value for customers prior to the availability of either new proxy resources or final shortlist project generation expected to be enabled by the Energy Gateway South transmission line as identified in the Company's 2020 All-Source Request for Proposals. Without Foote Creek II-IV, the risk of shortfalls is increased as is reliance on energy markets. In its current state, the existing Foote Creek II-IV facilities are no longer generating and turbines have been removed from the site pending repowering of the site. Repowering will allow the facilities to once again provide energy and capacity to serve load and reduce market reliance, while allowing the newly installed turbines to qualify for an additional 10 years of federal production tax credits (PTCs).

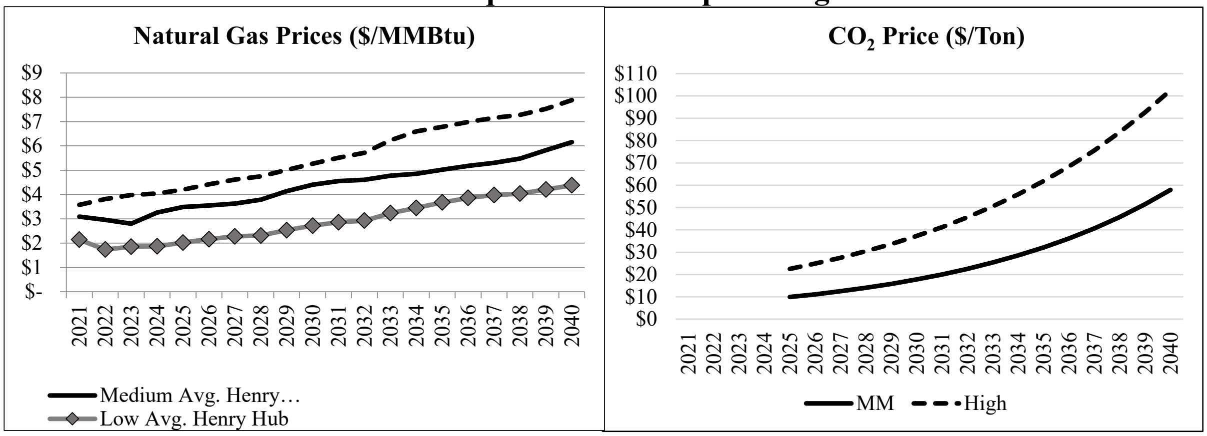
Q. Has the Company performed an updated analysis of Foote Creek II-IV after the filing of its 2021 IRP?

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

Q. Please summarize how this economic analysis supports the prudence of the Company's decision to acquire and repower the facilities.

A. The analysis used three price-policy scenarios, representing low, medium and high natural gas prices and zero, medium and high CO_2 prices. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario, the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario, and the price-policy scenario that pairs high natural gas prices with a high CO_2 price is referred to as the "HH" scenario. While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the LN and the HH scenarios provide informative analytical bookends scenarios. The natural gas and CO_2 price assumptions are summarized in Figure 1.

Figure 1. Price-Policy Assumptions used in the Economic Analysis of Foote Creek II-IV Acquisition and Repowering



In the "expected case" represented by the MM price-policy scenario through 2050, this analysis shows that Foote Creek II-IV will deliver $53.07 million in present-value net customer benefits. In the bookend LN scenario, a present-value net cost of $17.09 million is shown through 2050. In the HH bookend scenario, Foote Creek II-IV produces the highest customer benefits of $80.8 million in net present-value. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support the acquisition and repowering of the Foote Creek II-IV project.

Q. Please explain how you conducted your analysis.

A. The methodology is consistent with the approach used to perform the economic analysis of portfolios in the 2021 IRP. The system value of incremental wind energy for Foote Creek II-IV is calculated from two Plexos ST (short-term) model simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. The system value of incremental wind energy is then converted to a dollar per megawatt-hour (mWh) value by dividing the change in annual system cost by the change in incremental wind energy for both price-policy scenarios through 2040. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2038-2040 timeframe. The assumed system value, expressed in dollars per mWh, is applied to the incremental energy output associated with Foote Creek II-IV wind repowering.

Q. Please provide the results of your analysis.

A. Table 10 summarizes the PVRR differential (PVRR(d)) between cases, with and without Foote Creek II-IV acquisition and repowering. A negative value indicates the project is expected to benefit customers. This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the medium and high price-policy scenarios, nominal levelized net benefits are $25/MWh and $38/MWh, respectively. Under the low price-policy scenario there is a nominal levelized net cost of $8/MWh.

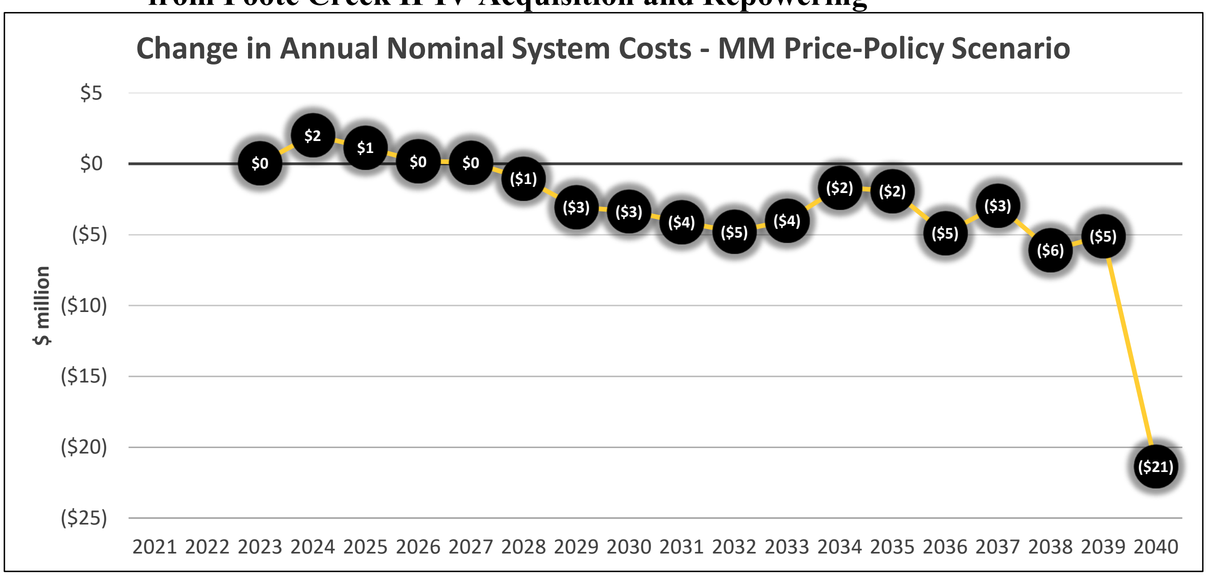
Table 10. Net Benefits from Foote Creek II-IV Acquisition and Repowering

	PVRR(d) Net (Benefit)/Cost ($million)	**Nom. Lev. Net Benefit ($/MWh of Incremental Energy)**
High Natural Gas, High CO_2	($80.80)	38/MWh
Medium Natural Gas, Medium CO_2	**($53.07)**	**25/MWh**
Low Natural Gas, No CO_2	$17.09	(8/MWh)

Q. Have you demonstrated the estimated change in nominal annual revenue requirement from Foote Creek II-IV repowering for the medium price-policy scenario?

A. Yes. Figure 2 reflects the change in nominal revenue requirement associated with project costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance expenses, the Wyoming wind-production tax, and production tax credits. The project costs are netted against system benefits as described above. Foote Creek II-IV repowering reduces or maintains nominal revenue requirement in all but years two and three of its depreciable life.

Figure 2. (Reduction)/Increase in Total-System Annual Revenue Requirement from Foote Creek II-IV Acquisition and Repowering



These results support the inclusion of Foote Creek II-IV acquisition and repowering to support customer needs with minimal risk.

VII. CONCLUSION

Q. What is your recommendation?

A. My testimony provides information on the following topics and makes the following recommendations:

- PacifiCorp has provided additional information on the retirement dates of certain coal units and the 2021 IRP analysis that was used to arrive at those retirement dates consistent with the Commission's directives from the 2019 Rate Case.
- PacifiCorp recommends that the Commission find PacifiCorp's load forecast as reasonable and prudent for use in this general rate case.
- Finally, I recommend that the Commission find the acquisition and repowering of Foote Creek II-IV as reasonable and prudent and support the inclusion of project costs in customer rates once the facilities are placed in-service.

Q. Does this conclude your direct testimony?

A. Yes.