Docket No. 20000-___-ER-23
Witness: Thomas R. Burns

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Thomas R. Burns

March 2023

I. INTRODUCTION AND QUALIFICATIONS

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

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

Q. Please describe your education and professional experience.

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

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for aspects of PacifiCorp's resource planning and procurement functions, which include the integrated resource plan ("IRP"), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this general rate case, I oversee the 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.

II. PURPOSE OF TESTIMONY

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

A. I provide economic analyses and describe the customer benefits that support PacifiCorp's decisions to acquire and repower the Foote Creek II-IV and Rock River I wind energy facilities in Wyoming ("Wind Facilities"), and provide the Company's updated sales and load forecast for Wyoming.

Q. Please provide an overview of your Foote Creek II-IV and Rock River I testimony.

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

Benefits for Foote Creek II-IV range from $53.07 million when using medium natural gas and medium CO_2 assumptions to $80.8 million for high natural gas and high CO_2 assumptions prior to adjusting for benefits from the Inflation Reduction Act ("IRA"). These benefits increase to $76.49 million when using medium natural gas and medium CO_2 assumptions and $104.23 million for high natural gas and high CO_2 assumptions when factoring in the IRA. For Rock River I, customer benefits range from $30.15 million when using medium natural gas and medium CO_2 assumptions to $67.76 million for high natural gas and high CO_2 assumptions prior to adjusting for the IRA. These benefits increase to $54.09 million when using medium natural gas and medium CO_2 assumptions and $91.69 million for high natural gas and high CO_2 assumptions when factoring in the IRA.

Conservatively, these benefits do not assign any value to the renewable energy credits ("RECs") that will be generated by the Wind Facilities.

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

A. Yes.

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

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

A. As described in the testimony of Company witness Mr. Timothy J. Hemstreet, PacifiCorp is acquiring and repowering the 43 megawatt ("MW") Foote Creek II-IV and 50 MW Rock River I wind facilities. This involves installing 11 modern wind turbine generators ("WTGs") at the Foote Creek facilities, and 19 WTGs at the Rock River I facility. These new turbines will increase the power generation from the previous capability and allow customers to benefit from these favorable wind sites. My testimony below provides the economic justification for the Company's decision to acquire and repower the Wind Facilities.

A. The 2021 IRP and IRP Update

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

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk to develop the Company's plans to provide reliable and reasonably priced service 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.

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. Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process which typically spans at least a full year 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. Did the Company's 2021 IRP identify a need for additional resources to serve PacifiCorp's customers?

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

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

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost

[1] 2021 IRP, Vol. I, Table 6.11.

and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflects a cost-conscious plan that includes near-term investments in renewable resources that can capture tax credits before they expire or decrease and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Can you describe the methodology that PacifiCorp used in the 2021 IRP to derive the preferred portfolio?

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

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

A. Yes. Both the Foote Creek II-IV and Rock River I acquisition and repowering projects were included as part of the least-cost, least-risk 2021 IRP preferred portfolio.[2]

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

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

A. Both projects are anticipated to be fully online and serving customers before 2025. This timing enables both projects 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 Gateway South transmission line as identified in the Company's 2020 All-Source Request for Proposals ("2020AS RFP"). Without both projects, the risk of shortfalls is increased as is reliance on energy markets. In their current states, the existing Foote Creek II-IV and Rock River I facilities are not operating as turbines have been removed pending the repowering of the sites. Repowering will allow the facilities to once again provide energy and capacity to serve load and reduce market reliance, while allowing the newly installed turbines to qualify for substantial production tax credits ("PTCs").

Q. Did the Company prepare an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[3]

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

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

[3] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022) (available here).

procurement activities that occurred since the 2021 IRP, and present an updated load-and-resource balance and an updated resource portfolio.

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

A. Yes. As discussed in Mr. Link's testimony, the need increased due to an increase in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[4] In 2025, the resource need is 1,867 MW, an increase of 240 MW, or approximately 15 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[5] And the most recent load forecast is even higher than that assumed in the 2021 IRP Update.

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

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

A. Yes. Both were included in the preferred portfolio identified in the 2021 IRP Update.[6]

---

[4] *Id.,* at Table 4.2.
[5] *Id.,* at 2.
[6] *Id.,* at Ch. 7 Action Plan Status update, Action Item 2b, at 100.

B. Assumptions and Results

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

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

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

A. The economic analysis for each of the projects included 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.

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 the Wind Facilities. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO_2 price assumptions are summarized in Table 1.

Table 1. Price-Policy Assumptions

Price-Policy Scenario	**Henry Hub Natural Gas Price (Levelized \$/MMBtu)***	**CO_2 Price Description**
HH	\$5.64	22.57/ton starting 2025 rising to 102.48/ton in 2040
MM	\$4.44	\$9.93/ton starting in 2025 rising
LN	\$2.94	None
*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 recent OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, May 2021 is the prompt month in this case. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecasted prices.

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

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

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

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

Q. Please explain how you conducted your analyses.

A. For both projects, the methodologies are consistent with the approach used to perform the economic analysis of portfolios in the 2021 IRP. The system value of incremental wind energy for each project is calculated from two PLEXOS ST model simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. The system value of incremental wind energy is then converted to a dollar-per-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 each of the wind repowering projects.

Q. Were your initial economic analyses of the Wind Facilities conducted prior to passage of the IRA?

A. Yes.

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

A. Based on existing law, PacifiCorp's initial economic analyses assumed that Foote Creek II-IV and Rock River I qualified for 60 percent of available PTCs. After passage of the IRA, the Company understands that the Wind Facilities now qualify for 110 percent of available PTCs. The Company has updated its economic analyses to reflect the new PTC value for both projects, and the results are reflected in Tables 2 and 3 below.

Q. Please summarize the present value revenue requirement differential ("PVRR(d)") and levelized results for Foote Creek II-IV.

A. Table 2 summarizes the PVRR(d) between cases, with and without Foote Creek II-IV acquisition and repowering, for customer benefits prior to, and after passage of, the IRA. This table also presents the same information on a levelized dollar-per-MWh basis.

Table 2. Foote Creek II-IV (Benefits)/Costs

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

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

After passage of the IRA, customer benefits increased substantially: Foote Creek II-IV will now deliver $76.49 million in present-value net customer benefits in the MM scenario and $104.23 million in the HH scenario. Importantly, the only scenario where Foote Creek II-IV was expected to generate customer costs prior to passage of the IRA—the LN scenario ($17.09 million)—has transformed to a $6.33 million customer benefit. While the Company decided to move forward with Foote Creek II-IV prior to passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

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

A. Yes. The Company updated its economic analysis in 2022 to support the Company's decision to acquire and repower Rock River I.[7]

[7] *See also, In re RMP's Application for a Certification of Public Convenience and Necessity to Construct New Wind Turbines and Update Collector Lines at the Existing Rock River I Wind Energy Facility,* Docket No. 2000-613-EN-22 (Record No. 17017), Order 29130 (Feb. 3, 2023) (requiring the Company to update its analysis of Rock River I to reflect post-IRA benefits).

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

A. Table 3 summarizes the PVRR(d) between cases, with and without Rock River I acquisition and repowering, for customer benefits prior to, and after passage of, the IRA. This table also presents the same information on a levelized dollar-per-megawatt-hour basis.

Table 3. Rock River I (Benefits)/Costs

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

Prior to passage of the IRA, Rock River I was expected to deliver $30.15 million in present-value net customer benefits in the MM scenario, and $67.76 million in the HH scenario. This is contrasted with $8.82 million cost in the LN scenario. Under the MM and HH scenarios, nominal levelized net benefits are $14/MWh and $32/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $4/MWh. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering Rock River I.

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

While the Company decided to move forward with Rock River I prior to passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

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

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

IV. SALES AND 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 ("load"), and number of bills by rate schedule for the 12-month period ending December 31, 2024. 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 PacifiCorp prepare the sales and load forecast used in this filing?

A. The sales and load forecast used in this filing was completed in May 2022. The May 2022 sales and load forecast is the most recent forecast of sales and loads prepared by the Company.

Q. What is the difference between sales and load?

A. Sales are measured at the customer meter, while load is measured at the generator or system input level.

Q. How did the Company use the May 2022 sales and load forecast in its preparation of this case?

A. The May 2022 load forecast was used by Mr. Nicholas L. Highsmith to calculate the inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by Mr. Robert M. Meredith to allocate costs between customer classes and to design rates that reflect the cost of service. The load forecast was also used by Mr. Ramon J. Mitchell to calculate NPC.

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

A. PacifiCorp first develops 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 forecast energy sales for 2024.

A. Table 4 provides the forecasted energy sales for the calendar year 2024.

Table 4. Test Period Sales Forecast (MWh)

Customer Class	Total-Company	Wyoming
Residential	17,848,776	1,014,739
Commercial	24,095,866	1,407,275
Industrial	18,865,604	6,586,076
Irrigation	1,412,814	27,373
Lighting	95,519	11,791
Total	62,318,579	9,047,255

Q. How does the total-Company sales forecast for 2024 compare to the sales forecast used in the 2020 rate case?

A. As shown in Table 5, total-Company 2024 forecast sales for this case are 10.7 percent higher than the 2021 forecast sales used in the 2020 rate case. The difference in the forecasts is attributable to an increase in commercial and residential sales. The industrial class decrease in the forecast is attributable to the continuing industrial decline in Oregon and market uncertainty in Wyoming due to current national policies. The growth in the commercial class is related to data centers growth.

Table 5. Total-Company Sales Comparison (MWh)

Customer Class	CY 2021	CY 2024	Percentage Difference
Residential	16,314,413	17,848,776	9.4%
Commercial	19,256,803	24,095,866	25.1%
Industrial	19,176,292	18,865,604	-1.6%
Irrigation	1,469,416	1,412,814	-3.9%
Lighting	99,688	95,519	-4.2%
Total	56,316,612	62,318,579	10.7%

Q. How does the Wyoming sales forecast for 2024 compare to the sales forecast for the 2020 rate case?

A. As shown in Table 6, the 2024 Wyoming sales forecast for this case has decreased by 1.1 percent from the 2021 sales forecast used in the 2020 rate case. In Wyoming, the residential class forecast is higher due to an increase in air-conditioning loads. The industrial class decrease in the forecast is attributable to market uncertainty due to current national policies.

Table 6. Wyoming Sales Comparison (MWh)

Customer Class	CY 2021	CY 2024	Percentage Difference
Residential	935,057	1,014,739	8.5%
Commercial	1,392,763	1,407,275	1.0%
Industrial	6,785,720	6,586,076	-2.9%
Irrigation	24,819	27,373	10.3%
Lighting	11,800	11,791	-0.1%
Total	9,150,160	9,047,255	-1.1%

Q. How does the load forecast for the test period compare to the load forecast for the 2020 rate case?

A. As shown in Table 7 below, the 2024 Wyoming load forecast for this case has decreased by approximately 0.5 percent from the 12-months ended December 2021 forecast used in the 2020 rate case. The total-Company 2024 test period forecast load has increased by approximately 9.9 percent from the 12-months ending December 2021 forecast used in the 2020 rate case.

Table 7. State Level Load Comparison at Input Level (MWh)

Customer Class	CY 2021	CY 2024	Percentage Difference
California	881,850	868,360	-1.5%
Oregon	15,219,850	18,770,430	23.3%
Washington	4,558,260	4,577,440	0.4%
Idaho	3,976,120	4,003,680	0.7%
Utah	26,586,297	29,082,672	9.4%
Wyoming	9,689,150	9,644,810	-0.5%
Total	60,911,527	66,947,392	9.9%

Q. Please summarize the major updates used to produce this forecast as compared to the forecast used in the 2020 rate case.

A. The Company updated the following inputs:

- The historical data used to develop the monthly retail sales forecasts was updated from the prior historical period ending January 2019 to include the most recent data available at the time of the forecast. In Wyoming, the class level forecasts use the time period of January 2000 through February 2022.
- The Company updated the historical data period used to develop the monthly peak forecasts to include January 2000 through December 2021.
- The Company updated the economic drivers for each of the Company's jurisdictions using IHS Markit data released in March 2022.
- The Company updated the forecast of individual industrial and commercial customer usage based on the best information available as of March 2022.
- The time period used to calculate normal weather was defined as the 20-year time period of 2002 through 2021.

- The Company rolled forward the line loss calculation to the five-year period ending December 2021.
- The data used to develop temperature splines was rolled forward based on available customer class hourly data (October 2016 through September 2021).
- The Company used the residential use-per-customer model with appliance saturation and efficiency results released in October 2021.

Q. Are there any changes in the load forecast methodology since the 2020 rate case?

A. Yes. The changes in methodology include:

- The Company has updated the timeframe used for developing the jurisdictional hourly load shapes as well as the timeframe used to develop the chaotic normal weather pattern relied on in the forecast.
- In order to capture the most recent hourly weather trends, the May 2022 forecast used the most recent five years of actuals, 2017 through 2021, to develop jurisdictional hourly shapes over the forecast horizon.
- The weather pattern used to capture a normal amount of variability in daily weather across the Company's six state service territory was updated based on the period of 2013 to 2020 for the May 2022 forecast.
- The Company updated its peak models to remove base load from the historical peaks before model input and only modeled the incremental load above base load. The final peak forecast is the forecasted base load plus the peak adder calculated from the peak model.

A. Monthly Sales Forecast Methodology

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

A. For the residential class, PacifiCorp forecasts the number of customers using IHS Markit's forecast of number of households or population as the major driver. For the commercial class, PacifiCorp forecasts the number of customers using the population forecast as the major economic driver. For the industrial, irrigation and street lighting classes, the customer forecasts are fairly static and developed using time series or regression models without any economic drivers.

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

A. PacifiCorp 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. PacifiCorp models sales-per-customer for the residential class through a Statistically Adjusted End-Use model, which combines the end-use modeling concepts with traditional regression analysis techniques.

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

A. For the commercial class, PacifiCorp forecasts sales using regression analysis techniques with non-manufacturing employment or non-farm employment, as the economic drivers, in addition to weather-related variables. Also, similar to how the PacifiCorp forecasts its largest industrial customers, data center forecasts are based on input from the Company's regional business managers ("RBMs").

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

A. The majority of industrial customers are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of industrial customers (the largest on the system), PacifiCorp individually prepares forecasts based on input from the customer and the RBMs.

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

A. For the irrigation class, PacifiCorp 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 LED lighting adoption curve.

B. Hourly Load Forecast

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

A. After PacifiCorp 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. This forecast is based on average monthly historical peak-producing weather for the January 2002 through December 2021.

Second, hourly load forecasts are developed 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.

C. Forecasts by Rate Schedule

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, Mr. Meredith 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. PacifiCorp develops this forecast in two steps: (1) it forecasts test year sales by rate schedule; and (2) it proportionally adjusts the rate schedule sales forecasts so that the total matches the customer class forecast.

Q. Finally, how does PacifiCorp 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, PacifiCorp forecasts the number of bills by class and by rate schedule. Then, PacifiCorp proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills matches the customer class forecasted number of bills.

V. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analyses shows that the acquisition and repowering of Foote Creek II-IV and Rock River I are necessary and will provide substantial customer benefits compared to anticipated project costs.

Q. What is your recommendation?

A. As supported by PacifiCorp's economic analysis, I recommend that the Wyoming Public Service Commission ("Commission") determine that the Company's decisions to acquire and repower Foote Creek II-IV and Rock River I are prudent and reasonable. I also recommend the Commission approve the Company's sales and load forecast for use in this rate case.

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

Thomas R. Burns (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the *Vice President of Resource Planning and Acquisitions* 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 *Vice President of Resource Planning and Acquisitions*.

Further Affiant Sayeth Not.

Dated this _28_ day of February_________, 2023

Thomas R. Burns
Vice President Resource Planning & Acquisitions

STATE OF _Oregon______)
) SS:
COUNTY OF Multnomah)

The foregoing was acknowledged before me by THOMAS R BURNS on this 28TH day of FEBRUARY, 2023. Witness my hand and official seal.

Notary Public

My Commission Expires: 9/7/2026

OFFICIAL STAMP
SCOTT ASHLEY MEASE
NOTARY PUBLIC - OREGON
COMMISSION NO. 1028167
MY COMMISSION EXPIRES SEPTEMBER 7, 2026