REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Rick T. Link

May 2020

Q. Please state your name, business address, and position with PacifiCorp.

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource Planning and Acquisitions. I am testifying on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company").

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's 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 for 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 2016. Over this time period, I held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, and 2019 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 investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

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

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I provide the economic analyses that support the resource decisions for several plant investments included in the case for recovery in base rates. First, I demonstrate that the Company's decision to repower the Foote Creek I and Leaning Juniper wind facilities will provide benefits to customers. Second, PacifiCorp has acquired another wind resource, the Pryor Mountain Wind Project in Montana, which will achieve commercial operation in 2020. I present and explain the economic analysis that demonstrates that this investment is reasonable and prudent. Third, I present economic analyses supporting decisions on certain coal generation units—the conversion of Naughton Unit 3 to natural gas in 2020 and the closure of Cholla Unit 4 in 2020. Finally, I present PacifiCorp's sales and load forecast upon which this rate case filing is based.

Q. How have you organized your testimony?

A. I have divided my testimony into six sections, including this Section I. Section II of my testimony addresses repowering the Foote Creek I and Leaning Juniper wind facilities. I address PacifiCorp's new Pryor Mountain Wind Project in Section III of my testimony. Section IV presents PacifiCorp's resource decisions involving coal generation facilities, and Section V presents PacifiCorp's sales and load forecast. Finally, my conclusion is provided in Section VI.

II. REPOWERING OF LEANING JUNIPER AND FOOTE CREEK I

Q. Please describe the scope of PacifiCorp's full repowering project.

A. The full wind repowering project includes 13 wind facilities, representing approximately 1,040 megawatts ("MW") of installed wind capacity. In Docket No. 17-035-39 ("Repowering Proceeding"), the Company presented the economic analysis and received approval for 11 of the 13 wind facilities, totaling approximately 999.1 MW. The facilities approved in the Repowering Proceeding were Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap in Wyoming; and Marengo I, Marengo II and Goodnoe Hills in Washington.[1] This filing includes the 12th and 13th facilities, Leaning Juniper in Oregon and Foote Creek I in Wyoming, which present similar economic benefits to those projected from the first 11 facilities, as described further below.

[1] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities,* Docket No. 17-035-39, Report and Order at p. 26-27 (May 25, 2018). The wind facilities approved for repowering from this docket are Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, Dunlap I, Marengo I, Marengo II, and Goodnoe Hills. The Company is demonstrating that the benefits to repower the Leaning Juniper facility are prudent and in the public interest within this rate case.

Q. Is PacifiCorp seeking recovery in base rates for all 13 facilities in the repowering project in this general rate case ("GRC")?

A. Yes. All of the facilities will be in service by the rate-effective date for this proceeding so the Company is seeking to include the costs in base rates for all 13 of the repowering facilities.

Q. Generally, what are the benefits of the repowering project?

A. Repowering upgrades will increase output of the wind facilities by 27 percent, extend the operating lives of the facilities, and allow the facilities to requalify for federal production tax credits ("PTCs") for 10 additional years.

Q. What were the results of PacifiCorp's underlying economic analysis for the repowering projects that were presented in the Repowering Proceeding?

A. PacifiCorp provided the economic analysis in the Repowering Proceeding in February 2018,[2] which demonstrated significant customer benefits across a range of assumptions. Through the life of the repowered facilities in that proceeding, the Company's analysis showed net benefits ranging between $121 million to $466 million.[3] However, in the February 2018 analysis performed on an individual project basis, Leaning Juniper presented the lowest customer net benefits relative to other wind facilities.

Q. Please briefly describe what repowering the Leaning Juniper wind facility entails.

A. Repowering the Leaning Juniper wind facility involves upgrading the existing, operating wind facility with longer blades and new technology to generate more energy

[2] The February 2018 economic analysis was provided in my Supplemental Direct testimony in Docket No. 17-035-39 at p. 22.
[3] *Id*. at pp. 1 & 22-23.

in a wider range of conditions as described in the direct testimony of Mr. Timothy J. Hemstreet.

Q. Why was Leaning Juniper not approved as part of the Repowering Proceeding?

A. In its decision, the Utah Commission determined that in light of the low potential benefits for the project in the February 2018 analysis, the Company must demonstrate the prudence of repowering Leaning Juniper in a future rate case if the Company proceeded with the project.[4] The Company subsequently made the decision to repower the facility after changes to cost-and-performance projections for the project improved customer benefits relative to the benefits from the previous analysis. The negotiated changes that improved the cost-and-performance assumptions for repowering Leaning Juniper are further described in the direct testimony of Mr. Hemstreet.

Q. Please summarize the economic analysis that supports the Company's decision to repower Leaning Juniper.

A. In August 2018, PacifiCorp performed an economic analysis using the same basic methodology that was used in the February 2018 analysis. The August 2018 analysis incorporated the cost-and-performance improvements for the Leaning Juniper project, and used then-current modeling assumptions: System Optimizer ("SO") model and Planning and Risk model ("PaR") studies that were run through 2036, where capital is levelized and PTCs are applied on a nominal basis. A nominal revenue requirement analysis was also developed that extends through 2050, where both capital and PTCs are evaluated on a nominal basis. The August 2018 Leaning Juniper analysis used

[4] V*oluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Utah Public Service Commission, Docket No. 17-035-39, Report and Order at p. 20 (May 25, 2018).

medium natural gas and medium CO_2 price-policy assumptions and the most conservative low natural gas and zero CO_2 price-policy assumptions.

Q. How did the cost-and-performance assumptions change for Leaning Juniper in the August 2018 analysis relative to the February 2018 analysis?

A. After evaluating alternative equipment suppliers, the capital cost required to repower Leaning Juniper was reduced by approximately [redacted] percent from [redacted] million to [redacted] million and the expected increase in annual energy output increased from [redacted] percent to [redacted] percent.

Q. Please summarize the present-value revenue requirement differential ("PVRR(d)") results for the Leaning Juniper facility calculated from the SO model and PaR through 2036 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 1 summarizes the PVRR(d) results for the Leaning Juniper facility when applying low natural-gas and zero CO_2 price-policy assumptions. Results, which represent the PVRR(d) between cases with and without repowering the Leaning Juniper facility, are shown alongside those reported from the February 2018 analysis. The PVRR(d) results in Table 1 are from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. Under this most conservative price-policy scenario, the Leaning Juniper facility is still projected to deliver net benefits, and driven by improved cost-and-performance assumptions, these net benefits improve relative to the February 2018 PVRR(d) results and are aligned with the project-by-project results for other wind facilities presented in the Repowering

Proceeding. These results confirm that with updated assumptions, repowering the Leaning Juniper facility will provide customer benefits and is therefore prudent.

Table 1. Leaning Juniper SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions ($ million); February and August 2018

Wind Facility	SO Model PVRR(d)		PaR Stochastic-Mean PVRR(d)		PaR Risk-Adjusted PVRR(d)	
	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)
Leaning Juniper	$6	($5)	$3	($4)	$4	($4)

Q. Is there incremental customer upside to the PVRR(d) results calculated from the SO model and PaR through 2036 for Leaning Juniper?

A. Yes. As is the case for the February 2018 analysis, the PVRR(d) results presented in Table 1 do not reflect the potential value of renewable energy credits ("RECs") generated by the incremental energy output from the repowered facilities.

Q. Please summarize the PVRR(d) results for the Leaning Juniper facility calculated from the change in annual revenue requirement through 2050 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 2 summarizes the PVRR(d) results for the Leaning Juniper facility when applying low natural-gas and zero CO_2 price-policy assumptions. Results, which represent the PVRR(d) between cases with and without repowering the Leaning Juniper facility, are shown alongside those reported from the February 2018 analysis. The PVRR(d) results in Table 2 are based on system modeling results from the change in annual revenue requirement through 2050. Under this most conservative price-policy scenario, the

Leaning Juniper facility is still projected to deliver net benefits, and driven by improved cost-and-performance assumptions, these net benefits improve relative to the February 2018 PVRR(d) results. These results confirm that with updated assumptions, repowering the Leaning Juniper facility will provide customer benefits and is therefore prudent.

Table 2. Leaning Juniper Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million), with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions; February and August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost	
	February 2018 (2017$)	August 2018 (2018$)
Leaning Juniper	($0)	($4)

Q. Please describe the repowering of the Foote Creek I facility.

A. As discussed in Mr. Hemstreet's testimony, the Foote Creek I wind facility was originally developed more than 20 years ago. Because of its age and design, repowering of Foote Creek I involves the removal of all existing wind turbine equipment, including towers, foundations, and energy collection system, and replacement with new equipment and energy collector circuits appropriately sized for the new equipment. This is different from repowering the rest of PacifiCorp's wind fleet (including Leaning Juniper), where the existing towers, foundations, and energy collection systems remained in place and were able to accommodate more modern wind-turbine-generator equipment.

Repowering at the Foote Creek I facility will result in the replacement of 68 existing small-capacity wind turbines with 13 modern wind turbines, representing approximately 46 MW of wind resource nameplate capacity.

Q. Why was Foote Creek I not included in the Repowering Proceeding and your February 2018 economic analysis?

A. As discussed above, the scope of repowering the Foote Creek I facility is notably different than the other wind facilities. Moreover, unlike the other 12 wind facilities within the scope of the wind repowering project, PacifiCorp shared ownership of Foote Creek I with Eugene Water & Electric Board ("EWEB"). Further differentiating Foote Creek I from the other 12 wind facilities within the scope of the wind repowering project, Bonneville Power Administration ("BPA") was purchasing 37 percent of the output from Foote Creek I via a power-purchase agreement ("PPA") that was to terminate in April 2024. Taken together, it took additional time to engage in discussions with EWEB and BPA to determine whether the ownership structure and PPA could be modified to facilitate repowering the Foote Creek I wind facility. Ultimately, as Mr. Hemstreet describes in his testimony, PacifiCorp was able to clear the way for repowering by acquiring EWEB's ownership interest, terminating the PPA with BPA, and acquiring the master wind energy lease rights associated with the Foote Creek I site.

Q. When did PacifiCorp make the decision to repower Foote Creek I?

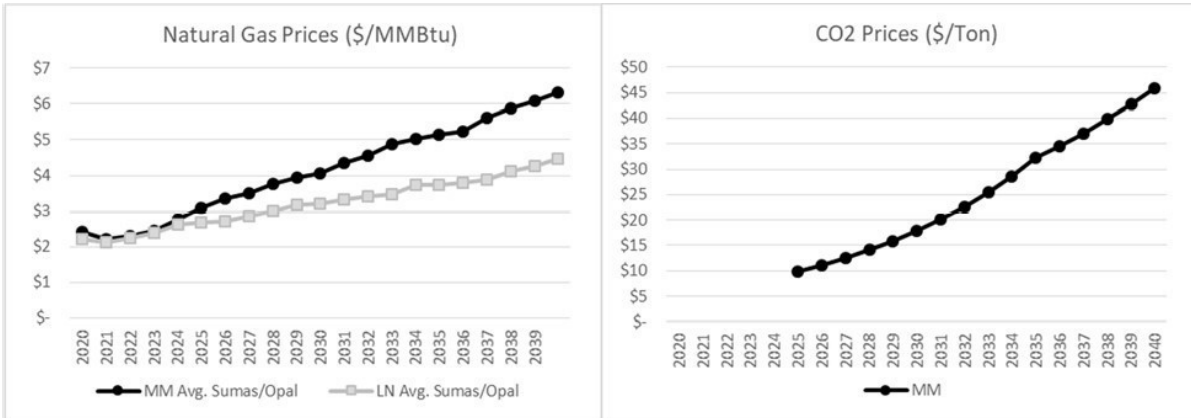
A. PacifiCorp made the decision to repower Foote Creek I in June 2019.

Q. Please summarize the economic analysis that supports the prudence of this decision.

A. PacifiCorp originally decided to repower Foote Creek I based on a June 11, 2019 economic analysis, indicating that repowering would produce present-value net customer benefits ranging between $3 million and $46 million. This analysis included acquisition of EWEB's 21.21 percent ownership interest and termination of the PPA with BPA. This analysis did not include acquisition of the master wind energy lease rights associated with the Foote Creek I site.

The economic analysis was updated July 16, 2019 to reflect the acquisition of the master wind energy lease rights associated with the Foote Creek I site. This analysis used two price-policy scenarios, representing low and medium natural gas prices and zero and medium CO_2 price scenarios. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario and the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario. 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 I Repowering



My analysis shows that Foote Creek I will deliver net customer benefits in both price-policy scenarios through 2050, producing present-value net customer benefits ranging between $6 million and $48 million.

Q. Please explain how you conducted your analysis.

A. The methodology is consistent with the approach used to perform the economic analysis of the other 12 facilities within the scope of the wind repowering project in Docket No. 17-035-39. The system value of incremental wind energy in eastern Wyoming is calculated from two PaR simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. I then converted the system value of incremental wind energy to a dollar-per-megawatt-hour value by dividing the change in annual system costs by the change in incremental wind energy for both price-policy scenarios through 2038. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2030-2038 time frame. The assumed system value, expressed in dollars per megawatt-hour, is applied to the incremental energy output associated with Foote Creek I wind repowering.

Q. Please provide the results of your analysis.

A. Foote Creek I repowering is forecasted to provide significant net benefits for customers. Table 3 summarizes the benefits calculated from changes in system costs through 2050, inclusive of the cost of repowering. This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the medium and low price-policy scenarios, nominal levelized net benefits are $29/megawatt-hour (“MWh”) and $3/MWh, respectively. These results are consistent with the range of the net benefits associated with other wind repowering facilities presented in my direct testimony in the Repowering Proceeding.

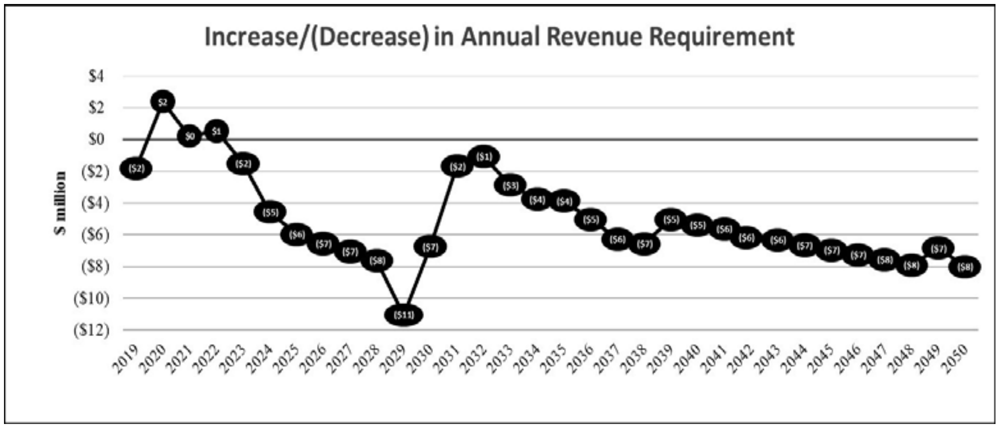
Table 3. Net Benefits from Foote Creek I Repowering

	PVRR(d) Net (Benefit)/Cost ($ million)	**Nom. Lev. Net Benefit ($/MWh of Incremental Energy)**
Medium Natural Gas, Medium CO_2	($48.20)	$29/MWh
Low Natural Gas, No CO_2	($5.60)	$3/MWh

Q. Have you demonstrated the estimated change in nominal annual revenue requirement from Foote Creek I 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 I repowering reduces nominal revenue requirement in all but the first three years of its depreciable life.

Figure 2. (Reduction)/Increase in Total-System Annual Revenue Requirement from Foote Creek I Repowering



III. PRYOR MOUNTAIN WIND PROJECT

Q. Did you conduct the economic analysis supporting acquisition of the Pryor Mountain Wind Project?

A. Yes. I prepared the economic analysis for the 240 MW Pryor Mountain Wind Project, which supports PacifiCorp's decision to move forward with the project as a resource decision that is least-cost and least-risk for customers. I completed this analysis in September 2019.

Q. Please provide background on the Pryor Mountain Wind Project.

A. In May 2019, PacifiCorp executed an agreement for the development rights associated with the Pryor Mountain Wind Project, located in Montana. In June 2019, PacifiCorp and Vitesse, LLC ("Vitesse") (a wholly-owned subsidiary of Facebook, Inc.) executed an agreement for the purchase of all RECs generated by Pryor Mountain over a 25-year period under PacifiCorp's Oregon Schedule 272 - Renewable Energy Rider Optional

Bulk Purchase Option. The opportunity evolved over a very compressed timeline, beginning in October 2018, with final terms on all material agreements completed before September 30, 2019. In September 2019, PacifiCorp executed the Engineering, Procurement, and Construction Contractor and wind turbine supplier agreements for the project. Mr. Robert Van Engelenhoven provides additional information about this project in his testimony.

Q. Please describe your economic analysis of the Pryor Mountain Wind Project.

A. I used the same methodology to perform the economic analysis of the Pryor Mountain Wind Project as I used to perform the economic analysis of the other resources addressed in my testimony. I relied on PaR runs with a simulation period covering the 2019 to 2038 time frame. System benefits from the development of the Pryor Mountain Wind Project, which includes sale of the associated RECs in accordance with the Oregon Schedule 272 Agreement, are based on two PaR simulations—one with incremental generation from the project and one without incremental generation from the project.

Q. What price-policy scenarios did you use in your economic analysis?

A. I used the same two price-policy scenarios as in PacifiCorp's project-by-project wind repowering analysis for Foote Creek I as summarized in Figure 1.

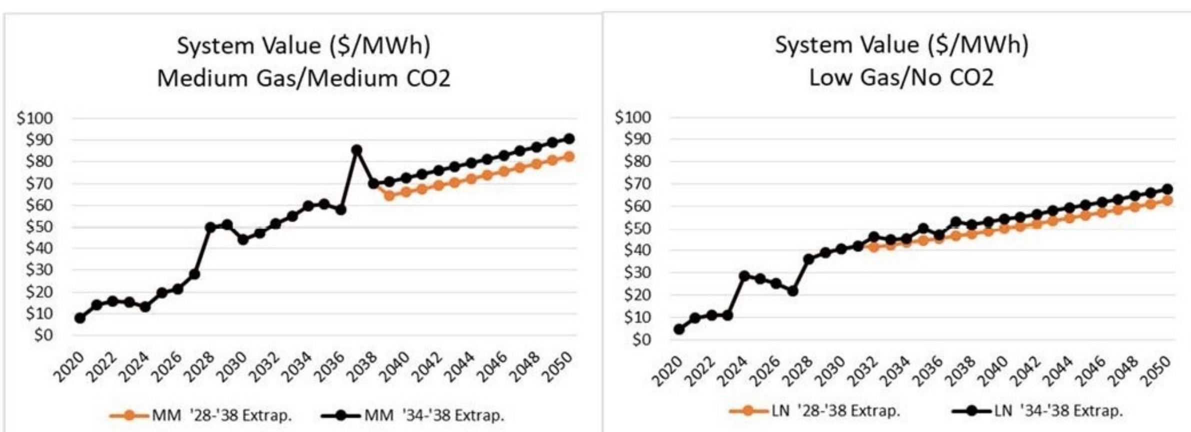
Q. Over what period did you analyze the costs and benefits of the Pryor Mountain Wind Project?

A. My analysis covers the 30-year life of the asset from 2020 through 2050.

Q. Please explain how you developed a forecast of the project's benefits beyond the 2038 time frame.

A. As with my economic analysis of the repowering project and Foote Creek I, the system value of incremental energy is converted to a dollar-per-megawatt-hour value by dividing the reduction in annual system costs associated with the Pryor Mountain Wind Project by the change in incremental energy from the Pryor Mountain Wind Project. This analysis was performed for the MM and LN price-policy scenarios through 2038. The value of energy is extended out through 2050 by extrapolating the system values calculated from modeled data over two different time frames—2028 to 2038, and 2034 to 2038. The assumed system value, expressed in dollars-per-megawatt-hour, is applied to the incremental energy output from Pryor Mountain Wind Project. The system value of the Pryor Mountain Wind Project is summarized for both price-policy scenarios in Figure 3.

Figure 3. System Value Used in the Economic Analysis of Pryor Mountain Wind Project



Q. Please provide the results of your economic analysis.

A. The Pryor Mountain Wind Project is expected to provide significant net benefits for customers. Table 4 summarizes the PVRR(d) benefits calculated from changes in system costs through 2050. This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the MM price-policy scenario, net benefits range between $69 million and $82 million. Under the LN price-policy scenario, the PVRR(d) benefits range between a $7 million benefit and a $1 million cost, depending upon the period used to extrapolate benefits beyond 2038. The execution of the Schedule 272 agreement with Vitesse was a necessary milestone to ensure the Pryor Mountain Wind Project could move forward and mitigates the risk of deteriorating value under a variety of price and policy scenarios, including the most conservative LN price policy scenario. Ms. Joelle R. Steward's testimony describes how Utah's share of the benefits from the Schedule 272 agreement will flow to customers. Additionally, while not explicitly analyzed, customer benefits would increase significantly with high natural-gas price and/or high CO_2 price assumptions.

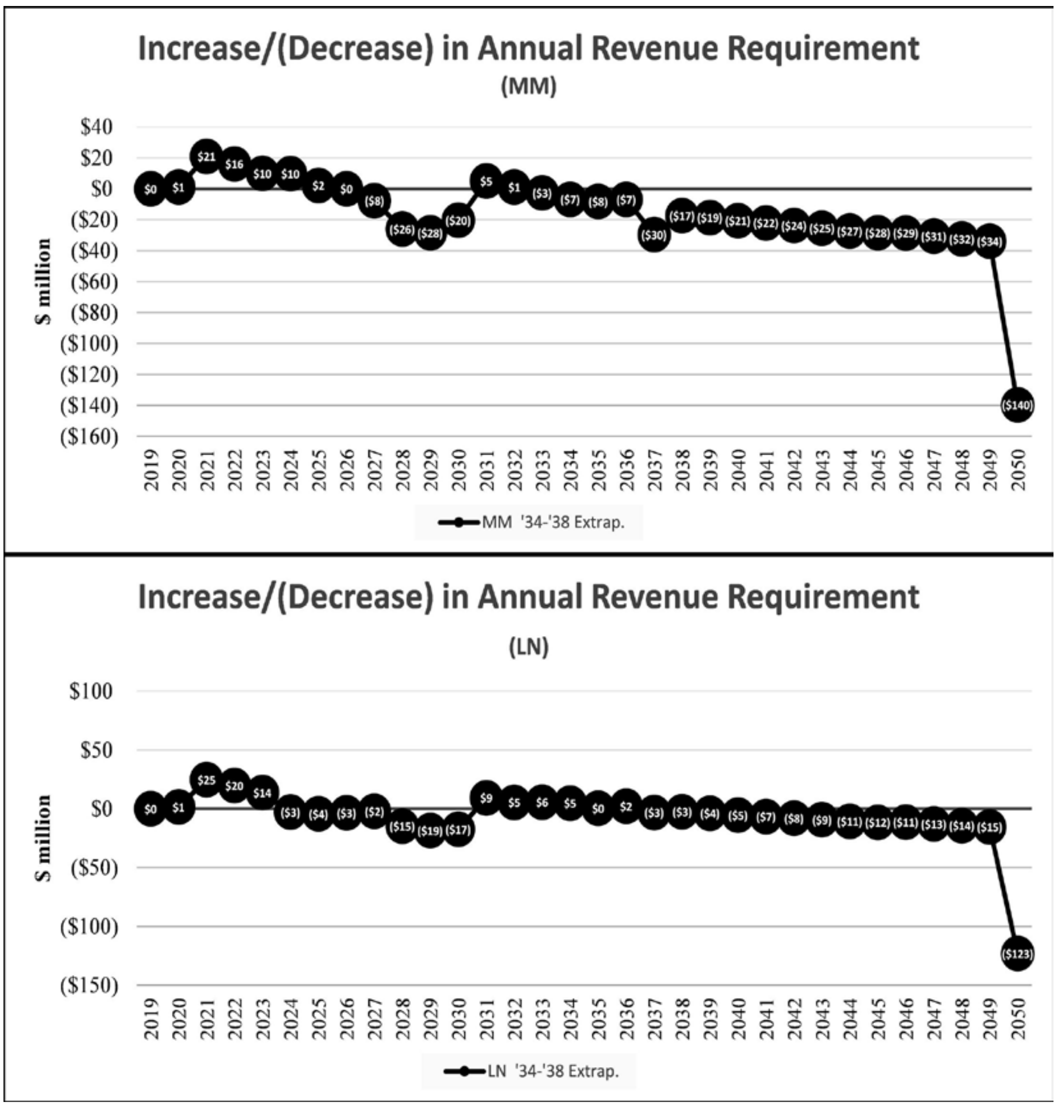
Table 4. Net Benefits from the Pryor Mountain Wind Project

Price-Policy Scenario (Extrapolation Method)	PVRR(d) Net (Benefit)/Cost ($ million)	Nom. Lev. Benefit ($/MWh of Incremental Energy)
MM ('28-'38 Extrapolation)	$(69)	$(7.22)
MM ('34-'38 Extrapolation)	$(82)	$(8.56)
LN ('28-'38 Extrapolation)	$1	$0.12
LN ('34-'38 Extrapolation)	$(7)	$(0.72)

Q. Have you analyzed the change in annual revenue requirement associated with the Pryor Mountain Wind Project?

A. Yes. Figure 4 shows the estimated change in nominal annual revenue requirement due to the Pryor Mountain Wind Project for the MM and LN price-policy scenarios with extrapolated benefits derived from modeled results over the period 2034 to 2038. This figure reflects the change in nominal revenue requirement associated with Pryor Mountain Wind Project netted against system benefits, which were calculated as described above. Considering both the MM and LN cases illustrated below, the Pryor Mountain Wind Project reduces nominal revenue requirement during a majority of its depreciable life.

Figure 4. (Reduction)/Increase in Total-System Annual Revenue Requirement from the Pryor Mountain Wind Project



IV. RESOURCE DECISIONS FOR COAL GENERATION UNITS

Q. Have you prepared economic analysis supporting major resource management decisions for coal generation units included in this case?

A. Yes. I present economic analysis supporting the conversion of Naughton Unit 3 to natural gas in 2020 and the closure of Cholla Unit 4 in 2020.

NAUGHTON UNIT 3 NATURAL GAS CONVERSION

Q. Please provide background on Naughton Unit 3.

A. The Naughton plant is located near Kemmerer, Wyoming. For several years PacifiCorp has been considering the conversion of Naughton Unit 3, a 280 MW coal-fired resource, to a natural gas facility for environmental compliance purposes. The most recent permit from the Wyoming Air Quality Division requires Naughton Unit 3 to cease coal firing by January 30, 2019, and that gas conversion be completed by June 24, 2021.

Q. Did PacifiCorp end coal generation at Naughton Unit 3 in 2019?

A. Yes. Coal generation from Naughton Unit 3 ended on January 30, 2019.

Q. Does the 2019 IRP's preferred portfolio reflect the conversion of Naughton Unit 3 to a natural gas facility in 2020?

A. Yes. In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. The 2019 IRP action plan provides that PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. The conversion will retrofit the unit to a natural gas-fueled, slow-start peaking unit at 75 percent maximum continuous rating, with expected generation of 247 MW. In his testimony, Mr. Van Engelenhoven describes the history and status of this conversion project, which is expected to be completed by mid-2020.

Q. In the 2019 IRP, how long does PacifiCorp assume Naughton Unit 3 will operate as a natural gas facility?

A. The 2019 IRP assumes Naughton 3 will operate as a natural gas facility through 2029.

Q. Does the conversion of Naughton 3 to natural gas benefit customers over other alternatives?

A. Yes. The cost of natural gas conversion is approximately $3 million, which equates to $12/kilowatt ("kW"). A new frame simple cycle combustion turbine located near the Naughton facility is estimated to cost $745/kW (2018 dollars). While the assumed design life of a new gas peaking asset is longer than the assumed life of Naughton Unit 3 once it is converted to a gas-fueled generating unit, the upfront capital required to convert natural gas is significantly less than the initial capital of new gas-fired generating unit. The gas conversion of Naughton Unit 3 represents an opportunity to maintain system capacity at a very low cost over a period in time where there are resource adequacy concerns in the region. PacifiCorp's analysis in the 2019 IRP demonstrates that, compared to early retirement of Naughton Unit 3, natural gas conversion has a PVRR(d) customer benefit ranging between $62 million and $121 million. The range of benefits is dependent upon the timing and magnitude of early coal unit retirement assumptions.

Q. Please explain the methods and assumptions used for the economic analysis in the 2019 IRP.

A. Informed by the 2019 IRP public-input process and results from coal studies that informed the 2019 IRP, initial portfolio development cases explored, among other things, alternative coal unit retirement assumptions. These cases also evaluated how system costs would be impacted if Naughton Unit 3 were converted to natural gas in 2020.

Case P-09 from the 2019 IRP is a variant of case P-03 that isolates the impact of converting Naughton Unit 3 to a 247 MW gas-fired facility in 2020. Both cases assume less accelerated coal retirements relative to the 2019 IRP preferred portfolio. Through the end of 2024, the total coal capacity assumed to retire in cases P-09 and P-03 is 280 MW, which represents Naughton Unit 3 ending coal-fired operations in 2019. Through the end of 2027, the total coal capacity assumed to retire in cases P-09 and P-03 is 1,734 MW. The PVRR of system costs in case P-09, where Naughton Unit 3 is assumed to convert to a 247 MW gas-fired facility in 2020, is $62 million lower than in case P-03.

Similarly, Case P-10 from the 2019 IRP is a variant of case P-04 that isolates the impact of converting Naughton Unit 3 to a 247 MW gas-fired facility in 2020. Cases P-10 and P-04 assume more accelerated coal retirements relative to the 2019 IRP preferred portfolio. Through the end of 2024, the total coal capacity assumed to retire in cases P-10 and P-04 is 1,730 MW. Through the end of 2027, the total coal capacity assumed to retire in these cases is 2,568 MW. The PVRR of total system costs in case P-10, where Naughton Unit 3 is assumed to convert to a 247 MW gas-fired facility in

2020, is $121 million. As compared to the PVRR(d) between cases P-09 and P-03, customer benefits are higher with the increase in accelerated coal retirements assumed in cases P-10 and P-04.

As noted above, cases developed in the initial portfolio development phase of the 2019 IRP were developed on the basis of outcomes of modeled results and stakeholder feedback. Subsequent cases produced during the initial portfolio development phase of the 2019 IRP were designed to evaluate cost and risk impacts of other variables (i.e., further analysis of coal unit retirement timing and price-policy assumptions). Based on the findings described above, subsequent cases produced in the 2019 IRP—including the case that was ultimately identified as the preferred portfolio—retained the assumption that Naughton Unit 3 is converted to a 247 MW gas-fired facility in 2020.

RETIREMENT OF CHOLLA UNIT 4 IN 2020

Q. Please provide background on Cholla Unit 4.

A. PacifiCorp owns 100 percent of Cholla Unit 4 which was commissioned in 1981 and has a generating capability of 395 MW. Arizona Public Service (“APS”) owns Cholla Units 1 and 3 (Unit 2 was retired in October 2015) and operates the entire Cholla facility. PacifiCorp owns approximately 37 percent of the plant’s common facilities.

Q. For environmental compliance reasons, is PacifiCorp required to cease operations at Cholla Unit 4 or convert it to natural gas by April 30, 2025?

A. Yes.

Q. Does PacifiCorp's 2019 IRP preferred portfolio include early retirement of Cholla Unit 4?

A. Yes. PacifiCorp's 2019 IRP preferred portfolio reflects customer benefits associated with Cholla Unit 4's retirement as early as 2020. Given the unique ownership structure at the Cholla plant, PacifiCorp's action plan commits PacifiCorp to initiating the process of retiring Cholla Unit 4 and removing it from service no later than January 2023 and earlier if possible.

Q. Does PacifiCorp currently plan to retire Cholla 4 by year-end 2020?

A. Yes. PacifiCorp has initiated the process of retiring Unit 4 and anticipates being able to achieve retirement by year-end 2020, earlier than the January 2023 timeframe initially set forth in the 2019 IRP action plan.

Q. Did PacifiCorp conduct additional economic analysis on the retirement of Cholla Unit 4 in 2020?

A. Yes. Further economic analysis building on the IRP studies confirm that early closure at the end of 2020 is expected to generate more present-value customer benefits relative to the plant continuing operation through April 2025.

Q. Please describe your economic analysis.

A. The economic analysis relies on an assessment of system value which compares the outcomes of the IRP's PaR scenarios with a simulation period covering the 2019 to 2025 timeframes. Consistent with the 2019 IRP preferred portfolio, the simulations utilize a range of natural gas price and carbon policy scenarios which incorporate a CO_2 price beginning in 2025 (medium natural gas price and medium CO_2 price assumptions (the "MM" price-policy scenario); low natural gas price and no CO_2 price assumptions (the "LN" price-policy scenario), and high natural gas price and no CO_2 price assumptions (the "HN" price-policy scenario)).[5]

Each price-policy scenario was run twice—once to update the 2019 preferred portfolio where Cholla Unit 4 is assumed to retire at the end of December 2020, and once assuming Cholla Unit 4 continues operation through the April 2025 timeframe. Each price-policy scenario showed an increase in net system costs when it was assumed that Cholla Unit 4 operates as a coal-fired facility through April 30, 2025.

The updated economic analysis confirms PacifiCorp's ongoing IRP analyses and demonstrates that retirement of Unit 4 by year-end 2020 will produce net customer benefits relative to a case where Unit 4 continues operating through April 2025. This outcome is consistent across a range of price-policy scenarios. This holds true even with incremental costs, such as the closure-related costs, in part because PacifiCorp will no longer incur the operating costs associated with running Unit 4.

Q. Please provide the specific results of your economic analysis.

A. Early closure at the end of 2020 is expected to generate between $96 million and $123 million in present-value customer benefits relative to an alternative where the unit continues to operate through April 2025. All three price-policy scenarios report an increase in net system costs when it is assumed that Cholla Unit 4 operates as a coal-fired facility through April 30, 2025, relative to the case where it is assumed to retire at the end of 2020.

[5] For both PaR runs produced under the MM price-policy scenario, price assumptions were developed from PacifiCorp's September 2019 official forward price curve. LN and HN price-policy scenarios are derived from third-party sources. Natural gas prices in the LN price-policy scenario do not drop below prices in the MM scenario until 2026-beyond the early retirement study period. Consequently, the primary difference between the MM and LN price-policy scenario is the absence of a CO_2 price in 2025 in the LN scenario.

As shown in Table 5, the year-end 2020 retirement case under the MM price-policy scenario shows $121 million in present-value customer benefits. In the HN and LN price-policy scenarios, the year-end 2020 retirement case produce present-value customer benefits of $96 million and $123 million, respectively. In each price-policy scenario, the cost to replace system capacity and energy in the early retirement case are lower than the ongoing costs of maintaining operations through April 2025.

Table 5. PVRR(d) Net (Benefit)/Cost of Year-End 2020 Retirement

Price Policy Scenario	PVRR(d) Net (Benefit)/Cost of a Year-End 2020 Retirement ($ million)
Medium Gas, Medium CO_2	($121)
Low Gas, No CO_2	($123)
High Gas, No CO_2	($96)

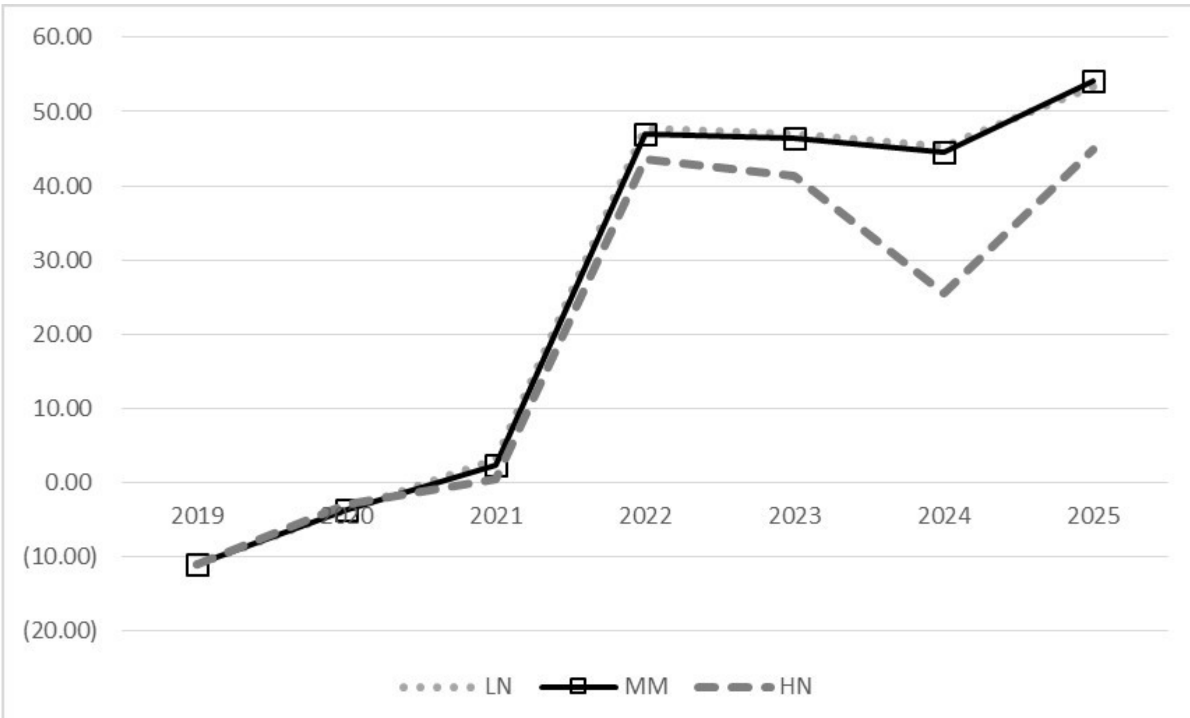
Q. Please explain these results in more detail.

A. In each price-policy scenario, when Cholla Unit 4 operates through April 2025, fuel expenses (ranging from $53 million to $73 million on a present-value basis) and run-rate fixed costs ($122 million on a present-value basis) exceed the net value of system balancing market transactions (ranging from $28 million to $31 million on a present-value basis). While continued operation of Cholla Unit 4 through 2025 reduces the cost of liquidated damages associated with the coal supply-agreement, these savings do not offset the ongoing operating cost of the unit.

The customer benefits in the MM and LN price-policy scenarios are similar. Annual cost differences in the system simulation between these two scenarios are very small, and consequently, present-value customer benefits in both scenarios are nearly identical. In the HN price-policy scenario, the high price of natural gas leads to a modest increase in generation, and consequently, fuel costs, from Cholla Unit 4.

However, the relative reduction in other system variable costs (i.e., fuel costs from other generators and system-balancing market transactions) is greater in the HN price-policy scenario, which reduces present-value customer benefits of the year-end 2020 early retirement case relative to the MM price-policy. Figure 5 illustrates the cost differentials for each price-policy scenario on an annual basis.

Figure 5. Nominal Net System (Benefit)/Cost of Year-End 2020 Retirement ($ million)

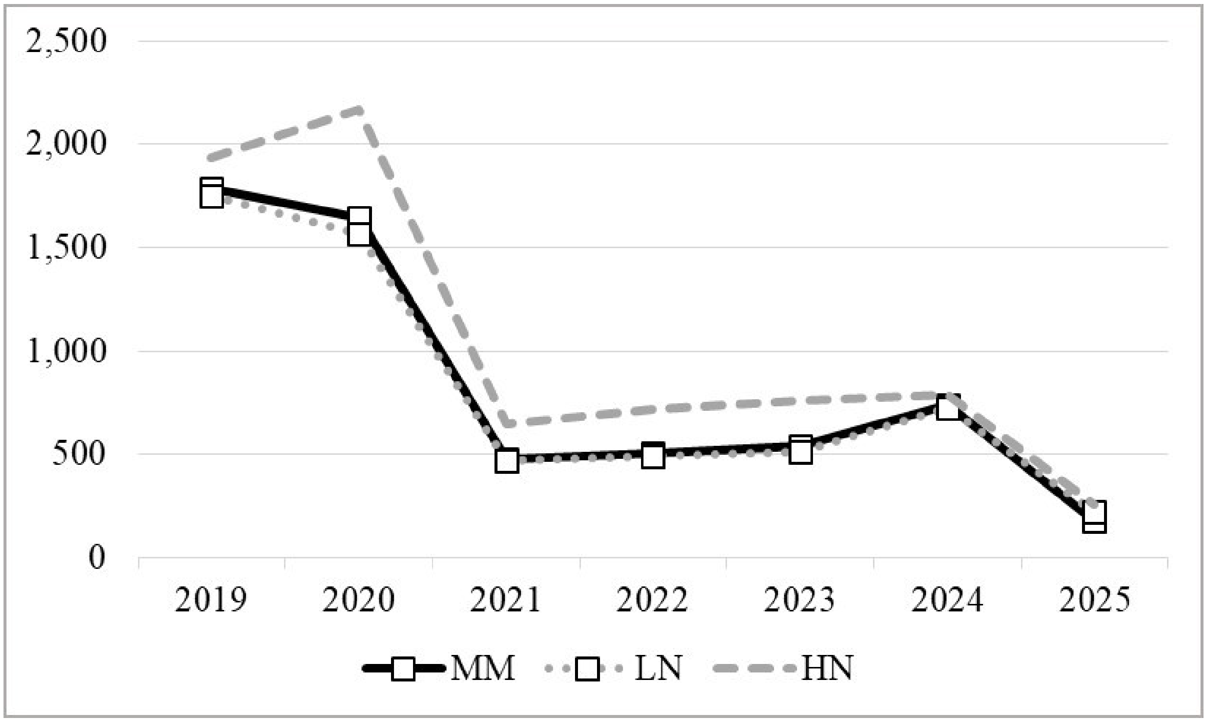


Q. Does early retirement of Cholla Unit 4 increase costs in 2020, followed by decreased costs between 2021 and 2025?

A. Yes. 2020 cost increases are primarily associated with an estimated $3.3 million of safe harbor lease early termination payments. PacifiCorp's acquisition of Cholla Unit 4 was subject to a pre-existing safe harbor lease, for federal income tax purposes, between APS, as property owner, and General Electric Company as tax lessor. PacifiCorp assumed certain rights and obligations of APS under the safe harbor lease with respect to Cholla Unit 4. Under the early retirement case, a casualty payment is assumed to be paid to General Electric Company for its loss of tax benefits ($2.9 million cost on a present-value basis), and the amortization of pre-paid availability and transmission charges related to the Mead-Phoenix line. When PacifiCorp acquired Cholla Unit 4, the Company paid APS a prepaid availability and transmission charge in April 1994 and April 1996. The charges are related to the construction of transmission facilities that enable and additional 150 MW of northbound firm transmission capability on the Phoenix-Mead transmission line. The prepaid transmission service cost began amortization over a 50-year life in May 1997 as PacifiCorp began receiving transmission credits on its bill from APS. Under the early retirement case, it is assumed the unamortized balance would be written off, which is estimated to have an unamortized balance of $9.2 million in 2020 and $6.7 million in 2025 ($3.9 million cost on a present-value basis).

Beyond 2020, the 2020 year-end early retirement of Cholla Unit 4 reduces net system costs through the assumed April 2025 retirement date. Over this period, projected generation from Cholla Unit 4 declines, and the value of energy net of fuel costs is insufficient to offset annual fixed operating costs. Annual generation levels for Cholla Unit 4 are summarized in Figure 6.

Figure 6. Cholla Generation by Price-Policy Scenario (GWh)



V. 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 (loads), and number of bills by rate schedule for the 12-month period ending December 31, 2021. 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 June 2019. The June 2019 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 June 2019 sales and load forecast in its preparation of this GRC?

A. The June 2019 load forecast was used by Mr. Steven R. McDougal to calculate the inter-jurisdictional allocation factors. The load forecast was also used by Mr. David G. Webb to calculate net power costs. The sales forecast by rate schedule was used by Mr. Robert M. Meredith to allocate costs between customer classes and to design rates that correctly reflect the cost of service.

Q. Has there been any updates to the forecast methodology used in this case compared to the forecast prepared for the 2014 general rate case, Docket No. 13-035-184 ("2014 Rate Case")?

A. Yes. Methodological updates for the residential customer model, transportation electrification and the street lighting sales model are discussed below.

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 forecast energy sales for 2021.

A. Table 14 provides the forecasted energy sales for the 12-month period ending December 31, 2021.

Table 6. Test Period Sales Forecast (MWh)

2020 GRC (CY 2021)		
	Total-Company	Utah
Residential	16,314,413	7,050,765
Commercial	19,256,803	9,517,080
Industrial	19,176,292	8,024,443
Irrigation	1,469,416	230,392
Lighting	99,688	45,983
Total	56,316,612	24,868,664

Comparisons to Prior Sales Forecasts

Q. How does the total-company sales forecast for 2021 compare to the sales forecast used in the 2014 Rate Case?

A. As shown in Table 7, total-company 2021 forecast sales are 3.7 percent higher than sales forecast used in the 2014 Rate Case. The difference in the forecasts is attributable to an increase in commercial, residential and irrigation load. The growth in the commercial class is related to data centers and reclassification of public authority sales as commercial sales. The industrial class decrease in the forecast is attributable to a decline in commodity prices over 2014 to 2015 timeframe.

Table 7. Total-Company Sales Comparison (MWh)

	Previous GRC	Current GRC	Percentage
	July '14 to June '15	CY 2021	Difference
Residential	15,421,549	16,314,413	5.8%
Commercial	17,429,594	19,256,803	10.5%
Industrial	19,770,205	19,176,292	-3.0%
Irrigation	1,262,520	1,469,416	16.4%
Public Authority	274,700	—	-100.0%
Lighting	143,180	99,688	-30.4%
Total	54,301,748	56,316,612	3.7%

Q. How does the Utah sales forecast for 2021 compare to the sales forecast for the 2014 GRC?

A. As shown in Table 8, the 2021 Utah sales forecast has increased by approximately 6.7 percent from the sales forecast used in the 2014 Rate Case. On a Utah basis, the commercial class increase reflects the continuing expansion of data centers and reclassification of public authority sales as commercial sales. The increase in residential class sales is driven by customer growth offset by a decline in use-per-customer. The decline in public street lighting is attributable to the adoption of light emitting diode ("LED") lighting.

Table 8. Utah Sales Comparison (MWh)

	Previous GRC	Current GRC	Percentage
	July '14 to June '15	CY 2021	Difference
Residential	6,401,383	7,050,765	10.1%
Commercial	8,327,476	9,517,080	14.3%
Industrial	8,029,187	8,024,443	-0.1%
Irrigation	189,890	230,392	21.3%
Public Authority	274,700	—	-100.0%
Lighting	77,730	45,983	-40.8%
Total	23,300,366	24,868,664	6.7%

Forecast Methodology

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

A. First, I describe the updates to 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.

Summary of Changes in Forecast Data and Assumptions

Q. Please summarize major updates used to produce the 2021 forecast as compared to the forecast used in the 2014 Rate Case.

A. The Company updated many of its data inputs and assumptions compared to the forecast prepared for the 2014 Rate Case. For each of these updates, the Company used the most recent information available.

1. For Utah, the residential, commercial, industrial and irrigation classes use a historical data period of January 2000 through January 2019. The lighting class uses the historical data period of January 2007 through January 2019.
2. The Company updated the historical data period used to develop the monthly peak forecasts to include January 2000 through December 2018.
3. The Company updated the economic drivers for each of the Company's jurisdictions using IHS Markit data released in October 2018.

4. The Company updated the forecast of individual industrial and commercial customer usage based on the best information available as of March 2019.

5. The time period used to calculate normal weather was defined as the 20-year time period of 1999 through 2018.

6. The Company rolled forward the line loss calculation to the five-year period ending December 2018.

7. The data used to develop temperature splines was rolled forward based on available customer class hourly data (October 2013 through September 2018).

8. The Company used the residential use-per-customer model with appliance saturation and efficiency results released in October 2018.

Q. Are there any changes in the load forecast methodology since the 2014 Rate Case?

A. The Company made the following changes to its load forecast methodology since the 2014 Rate Case:

1. The Company updated its residential customer forecasting methodology by adopting a differenced model approach in the development of the forecast of residential customers. Rather than directly forecasting the number of customers as was conducted for the 2014 Rate Case, the differenced model predicts the monthly change in number of customers. The Company performed a historical comparison of the forecasted results using both methods against actual customer counts and determined the differenced model produced a more accurate customer forecast.

2. The Company developed a transportation electrification projection based on current and expected electric-vehicle adoption trends. This projection was

incorporated as a post-model adjustment to the residential and commercial sales forecasts.

3. The Company incorporated a LED lighting adoption curve for its street lighting forecast. The adoption curve was developed to predict how the conversion to this more efficient technology is impacting the Company's sales.

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. For the commercial class, the Company forecasts the number of customers using the forecasted number of residential customers 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.

Monthly Sales Forecast Methodology

Q. What methodology does the Company use to forecast the 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 energy price.

Q. What methodology does the Company use to forecast the 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. Also, similar to how the Company forecasts its largest industrial customers, data center forecasts are based on input from the Company's regional business managers ("RBMs"). The treatment of data centers is similar to large industrial customer sales, which is discussed below.

Q. How does the Company 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 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 LED lighting adoption curve.

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 1999 through 2018.

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.

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. 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 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 matches the customer class forecasted number of bills.

Q. Please summarize the changes to the Company's sales and load forecast.

A. The Company's load forecast has been updated with the most recent information available at the time of the forecast and includes changes in methodology that the Company believes will more accurately forecast load. The changes in methodology employed in this forecast reflect the due diligence and analysis done by the Company that will improve the accuracy of the forecast.

VI. CONCLUSION

Q. Based on your testimony, what do you recommend to the Commission?

A. I recommend that the Commission conclude that PacifiCorp's repowering of the Leaning Juniper and Foote Creek I wind facilities and the acquisition of the Pryor Mountain Wind Project are reasonable and prudent. I also recommend that the Commission approve the costs of the resource decisions PacifiCorp has made with respect to its coal generation units.

Q. Does this conclude your direct testimony?

A. Yes.