REDACTED
Rocky Mountain Power
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Rick T. Link

June 2017

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 and Commercial Strategy. I am testifying in this proceeding on behalf of Rocky Mountain Power, a division of PacifiCorp.

Q. Please describe your current responsibilities.

A. I am responsible for PacifiCorp's integrated resource plan ("IRP"), structured commercial business and valuation activities, long-term commodity price forecasts, long-term load forecasts, and environmental strategy and policy activities. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and for implementing 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. From 2003 through 2016, I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, and 2017 IRPs, have been directly involved with implementing 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 Wyoming Public Service Commission, the Utah Public Service Commission, the Public Utility Commission of Oregon, and the Washington Utilities and Transportation Commission.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present and explain the economic analysis that shows PacifiCorp's decision to upgrade, or "repower," certain wind resources is prudent and provides significant customer benefits. I also summarize PacifiCorp's assessment of the wind repowering project in its 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis supports repowering approximately 999 megawatts ("MW") of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional ten years of federal production tax credits ("PTCs"), produce more energy, reset the thirty-year depreciable life of the assets, and reduce run-rate operating costs. PacifiCorp's economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, net power cost ("NPC") benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

The change in revenue requirement due to wind repowering was analyzed across nine different scenarios, each with varying natural gas and carbon dioxide ("CO_2") price assumptions. All nine scenarios show customer benefits, as measured by the change in present-value revenue requirement over the remaining life of the repowered wind facilities. With medium natural gas and medium CO_2 price assumptions, the present-value change in revenue requirement due to wind repowering shows $359 million customer benefit. Across all nine scenarios, the change in present-value revenue requirement due to repowering ranges from $41 million in customer benefits when assuming low natural gas prices and zero CO_2 prices to $589 million when assuming high natural gas prices and high CO_2 prices. These benefits conservatively do not assign any value to the incremental renewable-energy credits ("RECs") that will be produced by the repowered wind facilities. Over the remaining life of the repowered wind facilities, present-value benefits would improve for all scenarios by an additional $11 million for every dollar assigned to the incremental RECs that will be generated after repowering.

When the present-value revenue requirement is measured over a 20-year period through 2036, PacifiCorp's economic analysis demonstrates net customer benefits in seven of nine natural gas and CO_2 price scenarios (all scenarios except the two using the lowest natural-gas price assumptions).

The wind repowering project will reduce revenue requirement soon after the new equipment is placed in service in the 2019-to-2020 time frame. From 2021 through

2028, revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. In his testimony, Mr. Jeffrey K. Larsen explains Rocky Mountain Power's proposal to reflect the benefits of wind repowering in rates.

Sensitivity analysis shows that benefits of wind repowering substantially increase when combined with new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission project, which are the subject of a concurrent application. Sensitivity analysis also shows that there is additional upside to customer benefits if the new equipment is depreciated over a longer life and if current large-generator interconnection agreements ("LGIAs") are modified to enable repowered wind facilities to operate at their full capacity.

2017 INTEGRATED RESOURCE PLAN

Q. Did PacifiCorp analyze wind repowering in its 2017 IRP?

A. Yes. The preferred portfolio in the 2017 IRP, representing PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, includes repowering of 905 MW of existing wind resource capacity located in Wyoming, Washington, and Oregon. As discussed later in my testimony, PacifiCorp expanded the wind repowering scope to include its Goodnoe Hills wind facility. With the addition of Goodnoe Hills, this application covers PacifiCorp's proposal to repower approximately 999 MW of existing wind capacity.

Q. What led PacifiCorp to evaluate the wind repowering opportunity in its 2017 IRP?

A. As explained by Mr. Timothy J. Hemstreet, PacifiCorp purchased safe-harbor equipment from General Electric International, Inc., and Vestas American Wind Technology, Inc., in December 2016. Consistent with Internal Revenue Service ("IRS") guidance, these equipment purchases, totaling $77.8 million, secured an option for PacifiCorp to repower its fleet of owned wind resources, thereby qualifying them for the full value of federal PTCs.

Wind repowering presents an opportunity to deliver several different types of benefits for customers. First, federal PTCs will apply to 10 additional years of generation from each repowered wind resource. The current value of federal PTCs, which is adjusted annually for inflation by the IRS, is $24 per megawatt-hour ("MWh"). At a federal and state effective tax rate of 37.95 percent, the current PTC equates to a $38.68 per MWh reduction in revenue requirement that can be passed through to customers.

Second, existing wind resources will be upgraded with modern technology, which improves efficiency and increases energy output. The additional energy output from these zero-fuel-cost assets provides incremental NPC benefits for customers.

Third, repowering a wind resource, which replaces the mechanical equipment of an existing wind facility, resets the usable life of the asset (currently 30 years), thereby extending and increasing NPC benefits over the period in which the repowered wind resource would have otherwise been retired from service.

Finally, the turbine-supply contracts for repowering will include a two-year warranty on the new equipment, which will avoid capital expenditures that would otherwise be needed to replace or refurbish existing equipment. Moreover, PacifiCorp anticipates that new, modern equipment will have reduced failure rates. Further, before installing the new equipment, PacifiCorp can avoid capital replacement costs for component failures on the existing equipment. This cost savings will be partially offset by lost energy output for specific wind turbines from the time that component failures occur through the time that the new equipment is installed.

After executing its safe-harbor equipment purchase in December 2016, PacifiCorp developed a wind repowering sensitivity in the first quarter of 2017, for consideration in its 2017 IRP, to evaluate the net customer benefits of the wind repowering opportunity.

Q. What wind resources did PacifiCorp include in the wind repowering sensitivity presented in its 2017 IRP?

A. PacifiCorp assumed repowering 905 MW of existing wind resource capacity in the 2017 IRP. Of the 905 MW, approximately 594 MW of this capacity are located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plans, McFadden Ridge, and Dunlap), approximately 101 MW are located in Oregon (Leaning Juniper), and approximately 210 MW are located in Washington (Marengo). PacifiCorp has since expanded its economic analysis to include Goodnoe Hills, which is located in Washington.

Q. What were the results of the wind repowering sensitivity presented in PacifiCorp's 2017 IRP?

A. The 2017 IRP wind repowering sensitivity showed significant net customer benefits across a range of assumptions related to forward market prices and federal CO_2 policy based on the Clean Power Plan ("CPP").

Q. Did the wind repowering sensitivity influence selection of the preferred portfolio in the 2017 IRP?

A. Yes. The wind repowering sensitivity included in the 2017 IRP showed significant net customer benefits by lowering the projected system present-value revenue requirement ("PVRR") relative to other resource portfolio options. Consequently, wind repowering was included in the 2017 IRP preferred portfolio, which represents PacifiCorp's plan to deliver reliable and reasonably priced service with manageable risk for customers through specific action items.

Q. Did PacifiCorp include a wind repowering action item in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan, which lists the specific steps PacifiCorp will take over the next two to four years to deliver resources in the preferred portfolio, includes the following action item:

> PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016.
>
> - Continue to refine and update economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed.
> - By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills).
> - Pursue regulatory review and approval as necessary.
> - By May 2018, issue the engineering, procurement and construction (EPC) notice to proceed to begin implementing wind repowering for specific projects consistent with updated financial analysis.
> - By December 31, 2020, complete installation of wind repowering equipment on all identified projects.[1]

Q. Please summarize PacifiCorp's progress with this action item.

A. PacifiCorp refined and updated its economic analysis of plant-specific wind repowering opportunities, and is now including Goodnoe Hills in the wind repowering project. The rest of my testimony presents and explains this economic analysis.

[1] PacifiCorp 2017 Integrated Resource Plan, Volume I at 16 (Apr. 4, 2017).

Mr. Hemstreet explains that PacifiCorp continues to evaluate repowering of the Foote Creek facility in Wyoming, but due to differences in project scope for this older-vintage facility, Foote Creek is not proposed as part of the wind repowering project in this application. Mr. Hemstreet also discusses the need to execute contracts by early April 2018 and addresses the construction schedule.

SYSTEM MODELING METHODOLOGY

Q. Please summarize the methodology PacifiCorp used in its system analysis of the wind repowering project.

A. PacifiCorp relied upon the same modeling tools used to develop and analyze resource portfolios in its 2017 IRP to refine and update its analysis of the wind repowering project. These modeling tools calculate system PVRR by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the present-value revenue requirement differential ("PVRR(d)") between two simulations of PacifiCorp's system. One simulation includes the wind repowering project and the other simulation excludes the wind repowering project. Customers are expected to realize benefits when the system PVRR with wind repowering is lower than the system PVRR without repowering. Conversely, customers would experience increased costs if the system PVRR with wind repowering were higher than the system PVRR without wind repowering.

Q. What modeling tools did PacifiCorp use to perform its system analysis of the wind repowering project?

A. PacifiCorp used the System Optimizer ("SO") model and the Planning and Risk model ("PaR") to develop resource portfolios and to forecast dispatch of system resources in simulations with and without wind repowering.

Q. Please describe the SO model and PaR.

A. The SO model is used to develop resource portfolios with sufficient capacity to achieve a target planning-reserve margin. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system PVRR. In selecting the least-cost resource portfolio for a given set of input assumptions, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective demand-side-management ("DSM") resources—all within or connected to PacifiCorp's system. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable operations and maintenance, and emissions, as applicable), the cost of new DSM resources, and levelized revenue requirement of capital additions for existing coal resources and potential new generating resources.

PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves, volatility and uncertainty in key system variables. PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results. The PVRR from the PaR model reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable operations and maintenance costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed operations and maintenance costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

Q. How has PacifiCorp historically used the SO model and PaR?

A. PacifiCorp uses the SO model and PaR to produce and evaluate resource portfolios in its IRP. PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects. The models were used to support the successful acquisition of the Chehalis combined-cycle plant, to support selection of the Lake Side 2 combined-cycle resource through a RFP process, and to evaluate installation of emissions control equipment. These models will also be used to evaluate bids in the soon-to-be-issued 2017R RFP, which is being issued to solicit bids for new wind resources.

Q. Are the SO model and PaR the appropriate tools for analyzing the wind repowering opportunity?

A. Yes. The SO model and PaR are the appropriate modeling tools when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the wind repowering project. PaR provides additional granularity on how wind repowering is projected to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for the wind repowering opportunity that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP.

Q. How did PacifiCorp use PaR to assess stochastic system cost risk associated with wind repowering?

A. Just as it evaluates resource-portfolio alternatives in the IRP, PacifiCorp uses the stochastic-mean PVRR and risk-adjusted PVRR, calculated from PaR study results, to assess the stochastic system cost risk of repowering. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp uses a risk-adjusted PVRR to evaluate stochastic system cost risk. The risk-adjusted PVRR incorporates the expected value of low-probability, high-cost outcomes. The risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95^{th} percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to the wind repowering analysis, the stochastic-mean PVRR represents the expected level of system costs from cases with and without repowering.

The risk-adjusted PVRR is used to assess whether wind repowering causes a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

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

A. Yes. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the wind-repowering project under a range of assumptions regarding wholesale market prices and CO_2 policy ("price-policy") assumptions. These assumptions drive NPC-related benefits, and so it is important to understand how the net-benefit analysis is affected under a range of potential outcomes. PacifiCorp developed low, medium, and high scenarios for the market price of electricity and natural gas and zero, medium, and high CO_2 price scenarios. Each pair of model simulations—with and without repowering, in both the SO model and PaR—was analyzed under each combination of these price-policy assumptions. I summarize the assumptions for each price-policy scenario later in my testimony.

PacifiCorp also completed three sensitivity studies to assess how certain factors affect the net benefits of the wind repowering project. The first sensitivity quantifies how the net benefits of the project are affected by the depreciable life of repowered facilities. PacifiCorp's base analysis assumes that repowering will reset the 30-year depreciable life of the asset. Assuming the possibility that wind facilities with modern equipment might continue operating over a longer period, this sensitivity quantifies the economic impact if the depreciable life of new equipment on a repowered facility were reset at 40 years.

The second sensitivity quantifies how the net benefits of wind repowering are affected when combined with 1,180 MW of new Wyoming wind resources (860 MW of owned resources and 320 MW of contracted resources) and the Aeolus-to-Bridger/Anticline transmission project. Consistent with PacifiCorp's application for a certificate for public convenience and necessity for the new wind and transmission assets (filed concurrent with this wind repowering application), this sensitivity assumes the new wind and transmission is operational by the end of October 2020.

The third sensitivity builds on the new-wind-and-transmission sensitivity case by assessing how the net benefits of wind repowering are affected if the repowered facilities are able to operate at their full generating capability. This sensitivity assumes the additional capacity and energy is combined with the new wind and new transmission included in the prior sensitivity. As described by Mr. Hemstreet, PacifiCorp's base analysis assumes that the repowered wind facilities continue to operate within the limits of their existing LGIAs. The average incremental energy output is expected to increase by approximately 19.2 percent if the repowered facilities operate within their existing LGIA limits. If these limits are modified, the average incremental energy output rises to 20.8 percent. PacifiCorp is studying whether these LGIAs can be modified to increase incremental energy output from the repowered facilities, which would increase the net benefits of repowering.

Q. How did PacifiCorp assess which wind facilities to include in the scope of the wind repowering project in this application?

A. PacifiCorp completed a series of SO model and PaR studies to determine how the system PVRR changes when a specific wind facility is added or removed from the scope of the wind repowering project. Starting with the wind repowering scope assumed in the 2017 IRP preferred portfolio, covering 905 MW of existing wind resource capacity, PacifiCorp first removed the Leaning Juniper facility from the wind repowering scope because it has the lowest expected annual average capacity factor among the owned wind facilities in PacifiCorp's wind fleet. A wind facility's capacity factor is a strong indicator of whether repowering is cost-effective because it is representative of energy output and is therefore tied to the amount of PTCs that will be generated if the facility is repowered. The risk-adjusted system PVRR from the case eliminating Leaning Juniper from the wind repowering project scope was $7 million higher than the risk-adjusted system PVRR from the case including Leaning Juniper in the project scope. Based on these results, Leaning Juniper remains within the scope of the wind repowering project considered in this application.

Because repowering of the Leaning Juniper facility, which has the lowest expected annual capacity factor relative to other wind facilities in PacifiCorp's fleet, provides incremental net benefits, all remaining wind facilities within the project scope would generate more PTCs and provide even larger incremental net benefits if repowered. Consequently, PacifiCorp did not analyze any further reductions to the wind repowering scope beyond its analysis of Leaning Juniper.

PacifiCorp next evaluated how expanding the wind repowering scope to include Goodnoe Hills would affect the system PVRR. The risk-adjusted system PVRR from the case including Goodnoe Hills in the project scope was $20 million lower than the system PVRR from the case without Goodnoe Hills. Based on these results, Goodnoe Hills was added to the repowering project scope considered in this application. With

Goodnoe Hills included, the scope of the repowering project considered in this application covers 999.1 MW of existing wind capacity—594 MW of this capacity is located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plans, McFadden Ridge, and Dunlap), 100.5 MW is located in Oregon (Leaning Juniper), and 304.6 MW is located in Washington (Marengo and Goodnoe Hills).

Q. What key assumptions did PacifiCorp update since analyzing the wind repowering project in its 2017 IRP?

A. Beyond the price-policy assumptions used to analyze a range of NPC-related benefits, the updated wind repowering analysis reflects updated assumptions for up-front capital costs, run-rate operating costs, and energy output for both the existing and repowered wind facilities. PacifiCorp's analysis assumes an up-front capital investment totaling approximately $1.13 billion with a 19.2 percent average increase in annual energy output. The cost and performance assumptions for the wind facilities studied for this application are summarized in Confidential Exhibit RMP___(RTL-1).

Q. How did PacifiCorp model de-rates to its Wyoming 230-kV transmission system when evaluating the wind repowering project?

A. In its final 2017 IRP resource-portfolio screening process, PacifiCorp identified and quantified reliability benefits associated with the Aeolus-to-Bridger/Anticline transmission project. This new transmission project would eliminate de-rates caused by outages on 230-kV transmission system elements. Historical outages on this part of PacifiCorp's transmission system indicate an average de-rate of 146 MW over approximately 88 outage days per year, which equates to approximately one 146-MW, 24-hour outage every four days. Without knowing when these events might occur, de-rates on the existing 230-kV transmission system were captured in the SO model and PaR as a 36.5 MW reduction in the transfer capability from eastern Wyoming to the Aeolus area. In the sensitivity performed to quantify how the net benefits of wind repowering are affected when combined with new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission project, this de-rate assumption was eliminated when the new transmission project is assumed to be placed in service at the end of October 2020.

Q. How did PacifiCorp model line-loss benefits associated with the Aeolus-to-Bridger/Anticline transmission project when studying the wind repowering project?

A. Line-loss benefits are only applicable if the Aeolus-to-Bridger/Anticline transmission project is built and therefore were only considered in the sensitivity performed to quantify how the net benefits of wind repowering are affected when combined with new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission project. For this sensitivity, when the Aeolus-to-Bridger/Anticline transmission project is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental 11.6 average MW ("aMW") of energy, which equates to approximately 102 gigawatt hours ("GWh"), will be able to flow out of eastern Wyoming each year. The line-loss benefit was reflected in the SO model and PaR by reducing northeast Wyoming load by approximately 11.6 aMW each year.

Q. Did PacifiCorp analyze potential energy imbalance market ("EIM") benefits in its wind repowering analysis?

A. Yes. In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the EIM can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the wind repowering analysis by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the wind repowering project; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Q. How did PacifiCorp account for the unrecovered investments in the original equipment that will be replaced with new equipment?

A. The economic analysis assumes that PacifiCorp will fully recover the unrecovered investment in the original equipment and earn its authorized rate of return on the unrecovered balance over the remainder of the original 30-year depreciable life of each repowered facility. Mr. Larsen describes PacifiCorp's proposed accounting treatment for the replaced equipment.

Q. Did PacifiCorp assume any salvage value for the equipment that will be replaced with repowering?

A. No. But any salvage value for the existing equipment would decrease the unrecovered investment and increase customer benefits.

ANNUAL REVENUE REQUIREMENT MODELING METHODOLOGY

Q. In addition to the system modeling used to calculate present-value net benefits over a twenty-year planning period, has PacifiCorp forecasted the change in nominal-annual revenue requirement due to the wind repowering project?

A. Yes. The system PVRR from the SO model and PaR is calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*e.g.*, NPC, fixed operations and maintenance) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of repowering, project capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the SO model and PaR levelized?

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates.

Consider the potential implications of modeling nominal capital revenue requirement for a future generating resource needed in 2036, the last year of the 2017 IRP planning period. If nominal capital revenue requirement were assumed, the model would capture in its economic assessment of resource alternatives the highest, first-year revenue requirement capital cost without having any foresight on the potential benefits that resource would provide beyond 2036. If nominal capital costs were applied, the model's economic assessment of resource alternatives for the 2036 resource need would inappropriately favor less capital-intensive projects or projects having longer asset lives, even if those alternatives would increase system costs over their remaining life. Levelized capital costs for assets that have different lives and in-service dates is an established way to address these types of distortions in the comparative economic analysis of resource alternatives.

Q. How did PacifiCorp forecast the annual revenue-requirement impacts of the wind repowering project?

A. In the models that exclude repowered wind, the annual stream of costs for wind facilities that are within the wind repowering scope, including levelized capital, are removed from the annual stream of costs used to calculate the stochastic-mean system PVRR. Similarly, in the simulation that includes repowered wind, the annual stream of costs for repowered wind facilities, including levelized capital and PTCs, are temporarily removed from the annual stream of costs used to calculate the stochastic-mean PVRR. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the wind facilities that are within the wind repowering scope, represents the net system benefit caused by the wind repowering project.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable operations and maintenance and emissions costs for those scenarios that include a CO_2 price assumption), and fixed-cost benefits. To complete the annual revenue-requirement forecast, the change in fixed costs for those wind facilities included in the wind repowering scope, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by wind repowering.

Q. Over what time frame did PacifiCorp estimate the change in annual revenue requirement due to the wind repowering project?

A. The change in annual revenue requirement was estimated through 2050. This captures the full 30-year life of the new equipment installed on repowered wind facilities.

Q. How did PacifiCorp calculate the net annual benefits caused by wind repowering beyond the 20-year forecast period used in PaR?

A. The PaR forecast period runs from 2017 through 2036. The change in net system benefits caused by wind repowering over the 2028-through-2036 time frame, expressed in dollars-per-MWh of incremental energy output from wind repowering, were used to estimate the change in system net benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by wind repowering were divided by the change in incremental energy expected from the wind repowering project, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the repowered wind projects over the 2028-through-2036 time frame were levelized. These levelized results were extended out through 2050 at inflation. The levelized net system benefits per MWh of incremental energy output from the repowered wind projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from repowered wind projects over the same period.

Q. Why did PacifiCorp use PaR results from the 2028-through-2036 time frame to extend system cost impacts out through 2050?

A. Consistent with the 2017 IRP, PacifiCorp's wind repowering analysis assumes the Dave Johnston coal plant, located in eastern Wyoming, retires at the end of 2027. When this plant is assumed to retire, transmission congestion affecting energy output from resources in eastern Wyoming, where many repowered wind resources are located, is reduced. The incremental energy output from repowered wind resources provides more system benefits when not constrained by transmission limitations. Consequently, the net system benefits caused by wind repowering over the 2028-through-2036 time frame, after Dave Johnston is assumed to retire, is representative of net system benefits that could be expected beyond 2036.

Q. Did PacifiCorp calculate a PVRR(d) for the wind repowering project using its estimate of annual revenue-requirement impacts projected out through 2050?

A. Yes.

Q. Does the PVRR(d) calculated from estimated annual revenue requirement through 2050 capture wind repowering benefits not included in the PVRR(d) calculated from the 20-year forecast coming out of the SO model and PaR ?

A. Yes. The PVRR(d) calculated off of estimated annual revenue requirement extended out through 2050 captures the significant increase in projected wind energy output beyond the 20-year forecast period.

Q. Why is there a significant increase in projected wind energy output beyond the 20-year forecast period ending 2036?

A. The change in wind energy output between cases with and without repowering experiences a step change in the 2036-through-2040 time frame, when the wind facilities, originally placed in-service during the 2006-through-2010 time frame, would otherwise have hit the end of their depreciable life. Before the 2036-through-2040 time frame, the change in wind energy output reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, the change in wind energy output between a case with and without repowering reflects the full energy output from the repowered wind facilities that would otherwise be retired.

PRICE-POLICY SCENARIOS

Q. Please explain why price-policy scenarios are important when analyzing the wind repowering project.

A. Wholesale-power prices, often set by natural gas prices, and the system cost impacts of potential CO_2 policies influence the forecast of net system benefits from wind repowering. Wholesale-power prices and CO_2 policy outcomes affect the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable cost benefits, and system fixed-cost benefits of wind repowering. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the wind repowering analysis, PacifiCorp studied the economics of the wind repowering project under a range of different price-policy scenarios.

Q. What price-policy scenarios did PacifiCorp use in its wind repowering analysis?

A. PacifiCorp analyzed the wind repowering project under nine different price-policy scenarios. PacifiCorp developed three wholesale-power price scenarios (low, medium, and high), and similarly developed three CO_2 policy scenarios (zero, medium, and high). The nine price-policy scenarios developed for the wind repowering analysis reflect different combinations of these scenario assumptions.

Considering that there is a high level of correlation between wholesale-power prices and natural gas prices, the wholesale-power price scenarios were based on a range of natural gas price assumptions. This ensures consistency between power price and natural gas price assumptions for each scenario. PacifiCorp implemented its CO_2 policy assumptions through a CO_2 price, expressed in dollars-per-ton.

While it is unlikely that the CPP will be implemented in its current form, it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emission reductions. CO_2 price assumptions used in the price-policy scenarios are not intended to mimic a specific type of policy mechanism (*i.e.*, a tax or an allowance price under a cap-and-trade program), but are intended to recognize that there might be future CO_2 policies that impose a cost to reduce emissions. Table 1 summarizes the nine price-policy scenarios used to analyze the wind repowering project.

Table 1. Price-Policy Scenarios

Price-Policy Scenario	Natural-Gas Prices (Levelized $/MMBtu)*	CO_2 Price Description
Low Gas, Zero CO_2	$3.19	$0/ton
Low Gas, Medium CO_2	$3.19	$3.41/ton in 2025 growing to $14.40/ton in 2036
Low Gas, High CO_2	$3.19	$4.73/ton in 2025 growing to $38.42/ton in 2036
Medium Gas, Zero CO_2	$4.07	$0/ton
Medium Gas, Medium CO_2	$4.13	$3.41/ton in 2025 growing to $14.40/ton in 2036
Medium Gas, High CO_2	$4.13	$4.73/ton in 2025 growing to $38.42/ton in 2036
High Gas, Zero CO_2	$5.83	$0/ton
High Gas, Medium CO_2	$5.83	$3.41/ton in 2025 growing to $14.40/ton in 2036
High Gas, High CO_2	$5.83	$4.73/ton in 2025 growing to $38.42/ton in 2036
*Nominal levelized Henry Hub natural-gas price from 2018 through 2036.		

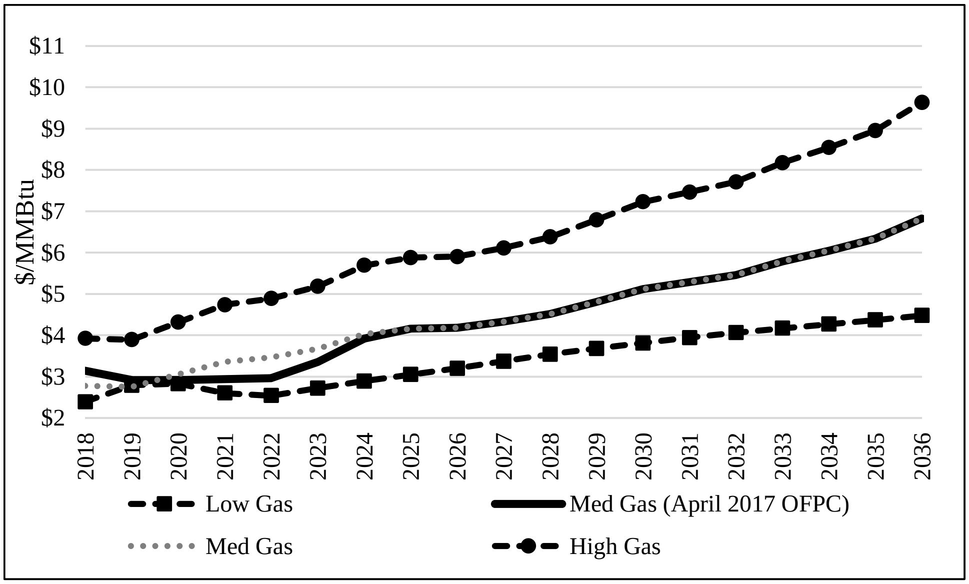
Q. Please describe the natural gas price assumptions used in the price-policy scenarios.

A. The medium-natural-gas-price assumptions that are paired with zero CO_2 prices reflect natural gas prices from PacifiCorp's official forward price curve ("OFPC") dated April 26, 2017. The OFPC uses observed forward market prices as of April 26, 2017, for 72 months, followed by a 12-month transition to natural gas prices based on a forecast developed by [redacted]. The medium, low, and high natural gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts developed by [redacted], and the U.S. Department of Energy's Energy Information Administration. Exhibit RMP___(RTL-2) shows the range in natural gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the wind repowering project.

The low-natural-gas-price assumption was derived from a low-price scenario developed by [redacted], which is based on surging growth in price-inelastic associated gas, technology improvements, stagnant liquefied natural gas exports, and an ever-expanding resource base. The medium-natural-gas-price assumption, which is used beyond month 84 in the April 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from [redacted] that is reasonably aligned with other base-case forecasts. The high-natural-gas-price assumption was based on a high-price scenario from [redacted]. The high-price scenario is based on risk aversion, whereby natural gas developers are reluctant to commit capital before demand, and the associated price response, materializes. This gives rise to exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in the third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

Figure 1 shows Henry Hub natural gas price assumptions from the April 2017 OFPC, low, medium, and high natural gas price scenarios. The April 2017 OFPC forecast only differs from the medium-natural-gas-price assumption in that it reflects observed market forwards through the first 72 months followed by a 12-month transition to [redacted] base-case forecast.

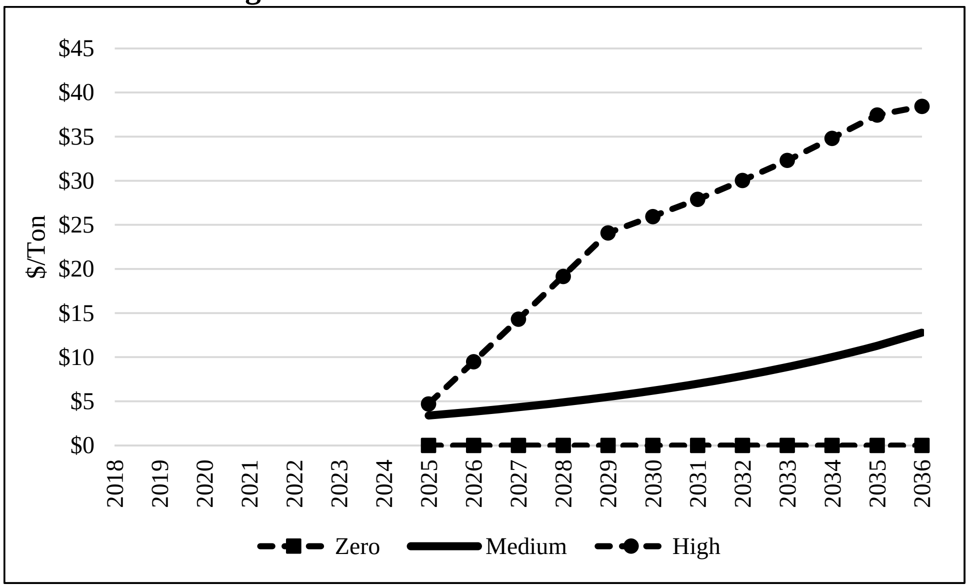
Figure 1. Nominal Natural Gas Price Scenarios



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

A. As with natural gas prices, the medium and high CO_2 price assumptions are based on third-party projections from [redacted]. Both forecasters assume CO_2 prices start in 2025. To bracket the low end of potential policy outcomes, PacifiCorp assumes there are no future policies adopted that would require incremental costs to achieve emissions reductions in the electric sector. In this scenario, the assumed CO_2 price is zero. Figure 2 shows the three CO_2 price assumptions used to analyze the wind repowering project.

Figure 2. Nominal CO_2 Price Scenarios



SYSTEM MODELING PRICE-POLICY RESULTS

Q. Please summarize the PVRR(d) results calculated from the SO model and PaR through 2036.

A. Table 2 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown from the SO model and from PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-3).

Table 2. SO Model and PaR PVRR(d)
(Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	$33	$43	$44
Low Gas, Medium CO_2	$0	$9	$8
Low Gas, High CO_2	($18)	($17)	($19)
Medium Gas, Zero CO_2	($33)	($24)	($25)
Medium Gas, Medium CO_2	($22)	($13)	($15)
Medium Gas, High CO_2	($41)	($35)	($36)
High Gas, Zero CO_2	($75)	($40)	($43)
High Gas, Medium CO_2	($64)	($34)	($37)
High Gas, High CO_2	($103)	($80)	($85)

Over a 20-year period, before accounting for the increase in incremental energy output beyond 2036, the wind repowering project reduces customer costs in seven out of nine price-policy scenarios. This trend occurs in the PVRR(d) calculated from both the SO model and PaR. The only price-policy scenarios without net customer benefits are those assuming the lowest natural gas prices when paired with either medium or zero CO_2 price assumptions. The PVRR(d) results show customer benefits under the price-policy scenario with low natural gas prices and high CO_2 prices, in all three of the medium-natural-gas-price scenarios, and in all three of the high-natural-gas-price scenarios. Under the central price-policy scenario, assuming medium-natural-gas prices and medium CO_2 prices, the PVRR(d) benefits range between $13 million, when based upon PaR-stochastic-mean results, and $22 million, when based upon SO model results.

The PVRR(d) results show that the benefits of the wind repowering project increase with natural gas prices and CO_2 prices. PVRR(d) results for scenarios where medium CO_2 prices are assumed with medium or high natural gas prices show a slight drop in benefits relative the zero-CO_2-price scenarios. This tends to be driven by changes to the timing of new resources in the outer years of the 20-year forecast period and would not likely persist if longer simulation periods were feasible.

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

A. Yes. The PVRR(d) results presented in Table 2 do not reflect the potential value of RECs generated by the incremental wind energy output from the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $4 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2036.

Q. Why do the PaR results tend to show a different level of benefits from the wind repowering project when compared to the results from the SO model?

A. The two models assess the system impacts of the wind repowering project in different ways. The SO model is designed to dynamically assess system dispatch, with less granularity than PaR, while optimizing the selection of resources to the portfolio over time. PaR is able to dynamically assess system dispatch, with more granularity than the SO model and with consideration of stochastic risk variables; however, PaR does not modify the type, timing, size and location of resources in the portfolio in response to its more detailed assessment of system dispatch. In evaluating differences in annual system costs between the two models, PaR's ability to better simulate system dispatch relative to the SO model results in lower benefits from repowering being reported from PaR in the earlier years of the forecast horizon. Because PaR cannot modify resource selections in response to its assessment of system dispatch, this effect is softened over the longer term, when changes to the resource portfolio in response to wind repowering are more notable.

Q. Does one of these two models provide a better assessment of the wind repowering project relative to the other?

A. No. The two models are simply different, and both are useful in establishing a range of wind repowering benefits through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across the same set of price-policy scenarios with consistent trends in the difference in PVRR(d) results between price-policy scenarios. The consistency in the trend of forecasted benefits between the two models, each having its own strengths, shows that the wind repowering benefits are robust across a range of price-policy assumptions and when analyzed using different modeling tools.

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

A. The risk-adjusted PVRR(d) results are very similar to the stochastic-mean PVRR(d) results. This indicates that the wind repowering project does not materially affect high-cost, low-probability outcomes that can occur due to volatility in stochastic variables like load, wholesale-market prices, hydro generation, and thermal-unit outages.

Q. Did PacifiCorp review how repowered wind facilities located in Wyoming affect the dispatch of Wyoming coal plants?

A. Yes. After repowering, the incremental energy output from the repowered wind facilities located in Wyoming could contribute to additional transmission congestion and require re-dispatch of coal resources in the region. Re-dispatch of coal resources can reduce NPC-related benefits in those hours where increased congestion would restrict the otherwise economic use of these assets to serve load or as a source for wholesale-market sales. To assess the potential level of re-dispatch that might be associated with repowering, PacifiCorp reviewed the modeled changes in Wyoming coal generation.

Confidential Figure 3 summarizes the change in annual coal generation from Wyoming coal resources due to wind repowering for the medium-natural-gas-and-medium-CO_2 price-policy scenario. The figure shows that re-dispatch of Wyoming coal resources leads to [redacted], when component failures on existing wind resource equipment is assumed to reduce output for specific wind turbines until the new equipment is installed. After the wind repowering project is completed, re-dispatch leads to [redacted] the Dave Johnston plant and Jim Bridger Unit 3 are assumed to retire at the end of 2027 and 2028, respectively. Between 2021 and 2028, average annual coal generation for PacifiCorp's ownership interest in Wyoming coal resources [redacted]. In the later years of the forecast period, changes in coal generation are influenced by changes to the resource portfolio. Wyoming coal plant re-dispatch for all price-policy scenarios is provided in Confidential Exhibit RMP___(RTL-4).

Confidential Figure 3. Change in Annual Generation from Wyoming Coal Plants Due to Repowering

[redacted]

ANNUAL REVENUE REQUIREMENT PRICE-POLICY RESULTS

Q. Please summarize the PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-5).

Table 3. Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($41)
Low Gas, Medium CO_2	($245)
Low Gas, High CO_2	($344)
Medium Gas, Zero CO_2	($362)
Medium Gas, Medium CO_2	($359)
Medium Gas, High CO_2	($401)
High Gas, Zero CO_2	($400)
High Gas, Medium CO_2	($274)
High Gas, High CO_2	($589)

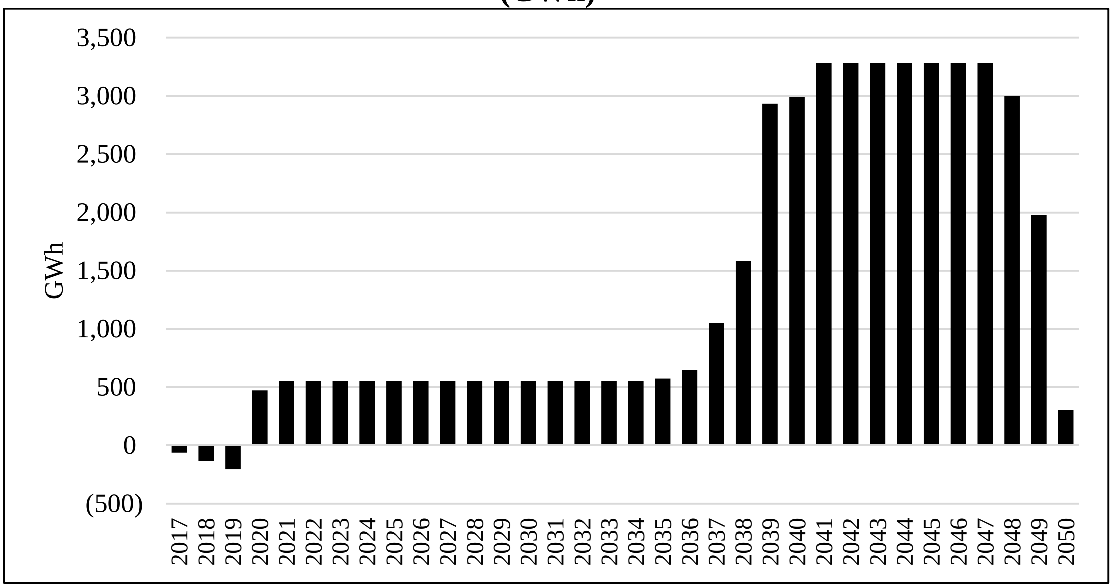
When calculated through 2050, which covers the remaining life of the repowered facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios, with PVRR(d) benefits ranging from $41 million in the low-natural-gas-and-zero-CO_2 scenario to $589 million in the high-natural-gas-and-high-CO_2 scenario. Under the central price-policy scenario, assuming medium natural gas prices and medium CO_2 prices, the PVRR(d) benefits are $359 million.

Q. What causes the substantial increase in PVRR(d) benefits when calculated off of nominal revenue requirement through 2050 relative to the PVRR(d) results calculated from the SO model and PaR results through 2036?

A. The PVRR(d) calculated from estimated annual revenue requirement through 2050 picks up the sizable increase in incremental wind energy output beyond the 20-year forecast period analyzed with the SO model and PaR. As discussed earlier in my testimony, the change in wind energy output between cases with and without wind repowering experiences a step change beyond this 20-year period, when the existing wind facilities would otherwise have hit the end of their depreciable life. Beyond the 20-year forecast period, the change in wind energy output between cases with and without repowering reflects the full energy output from the repowered wind facilities.

Figure 4 shows the incremental change in wind energy output resulting from the repowering project. Incremental energy output associated with wind repowering progressively increases over the 2036-through-2040 period, as wind facilities originally placed in service in the 2006-through-2010 time frame would have otherwise hit the end of their lives. Before 2036, and once all of the wind resources within the project scope are repowered, the average annual incremental increase in wind energy output is approximately 551 GWh. Beyond 2040, and before the new equipment hits the end of its depreciable life, the average annual incremental increase in wind-energy output is approximately 3,283 GWh.

Figure 4. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh)



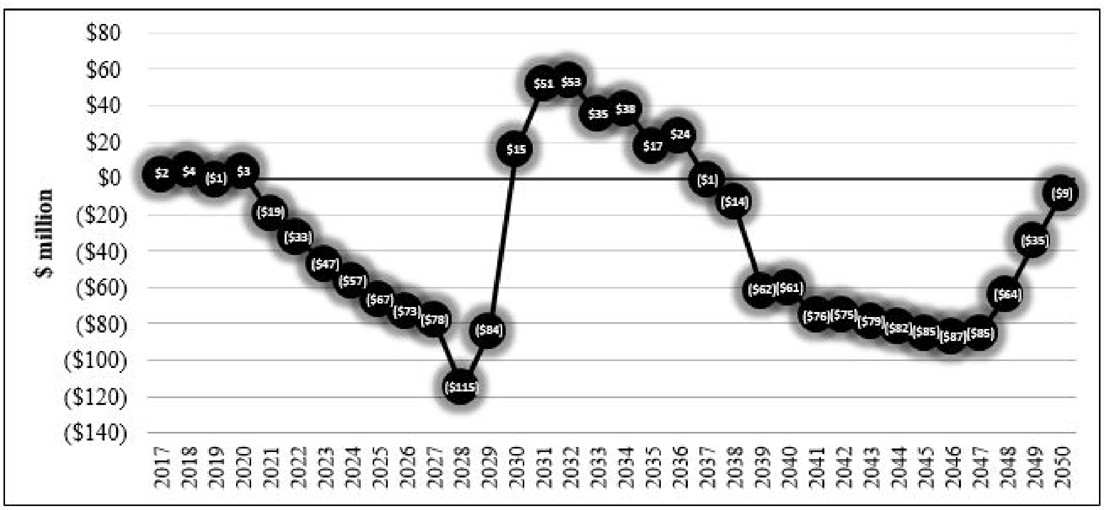
Q. Is there incremental customer upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?

A. Yes. As in the case with the PVRR(d) results calculated from the SO model and PaR results through 2036, the PVRR(d) results presented in Table 3 do not reflect the potential value of RECs produced by the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $11 million for every dollar assigned to the incremental RECs that will be generated from the wind repowering project through 2050.

Q. Please describe the change in annual nominal revenue requirement from the wind repowering project.

A. Figure 5 shows the estimated change in nominal revenue requirement due to wind repowering for the medium-natural-gas-and-medium-CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects 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 PTCs. The project costs are netted against system impacts of wind repowering, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the wind repowering project.

Figure 5. Total-System Annual Revenue Requirement with Wind Repowering ($ million)



Before repowering, the reduction in wind energy output due to component failures on the existing wind resource equipment is assumed to reduce wind energy output for specific wind turbines until the time new equipment is installed. This contributes to a slight increase in revenue requirement in 2017 and 2018 ($2 million to $4 million, total system). All but the Dunlap facility, which is repowered toward the end of 2020, are repowered in 2019. Over the 2019-to-2020 time frame, project costs reflecting partial-year capital revenue requirement net of PTCs and system cost impacts, cause slight changes to revenue requirement.

The wind repowering project reduces revenue requirement soon after the new equipment is placed in service in the 2019-to-2020 time frame. From 2021 through 2028, annual revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. On a total-system basis, annual revenue requirement is reduced by $19 million in 2021. The reduction in annual revenue requirement increases to $115 million by 2028. Revenue requirement increases once the PTCs expire toward the end of 2030. Annual revenue requirement is reduced over the 2037-through-2050 time frame when, as discussed earlier in my testimony, the incremental wind energy output associated with wind repowering increases substantially.

SENSITIVITY STUDY RESULTS

Q. Please summarize the results of the sensitivity that assumes the new wind equipment has a 40-year-depreciable life.

A. Table 4 summarizes the PVRR(d) results for the sensitivity assuming a 40-year life for new equipment. To assess the relative impact of the 40-year life, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which wind repowering was evaluated with a 30-year life. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 4. 40-Year-Life Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($60)	($22)	($38)
PaR Stochastic-Mean	($50)	($13)	($37)
PaR Risk-Adjusted	($52)	($15)	($37)

If the new equipment were depreciated over a 40-year life, reduced book depreciation would drive lower annual revenue requirement. In this sensitivity, PVRR(d) benefits increase by approximately $37 million relative to the benchmark case assuming a 30-year life for the new equipment.

Q. Please summarize the results of the sensitivity that includes new incremental wind and the planned Aeolus-to-Bridger/Anticline transmission project.

A. Table 5 summarizes the PVRR(d) results for the sensitivity assuming wind repowering is implemented along with 1,180 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project. To assess the relative impact of the new wind and transmission, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which wind repowering was evaluated as a stand-alone project. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 5. New Wind and Aeolus-to-Bridger/Anticline Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($114)	($22)	($91)
PaR Stochastic-Mean	($104)	($13)	($90)
PaR Risk-Adjusted	($116)	($15)	($101)

When the wind repowering project is combined with 1,180 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project, PVRR(d) benefits increase by between $91 million to $101 million relative to the benchmark case. This sensitivity shows that wind repowering benefits persist when combined with new wind and new transmission, and that the new wind and new transmission will provide significant incremental benefits for customers.

Q. Please summarize the results of the sensitivity that assumes repowered wind facilities can operate at their full capacity.

A. Table 6 summarizes the PVRR(d) results for the sensitivity that assumes repowered wind facilities can operate at their full capacity. The increased energy and capacity assumed in this sensitivity is in addition to the new wind and transmission assumed in the prior sensitivity. To assess the relative impact of this assumption on revenue requirement, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study assuming repowered wind resources operate within existing LGIA limits. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 6. Increased Wind Repower Capacity Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($109)	($114)	$4
PaR Stochastic-Mean	($106)	($104)	($2)
PaR Risk-Adjusted	($118)	($116)	($2)

If PacifiCorp is able to modify its LGIAs, the repowered wind facilities will be able to produce additional energy in those hours where wind energy output would otherwise have been curtailed to stay within current LGIA limits. If these LGIAs are modified, PVRR(d) this study suggests there may be additional upside to customer benefits, but they are not likely to be substantial.

CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis supports repowering approximately 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional ten years of federal PTCs, produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs. The economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, NPC benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

Q. What do you recommend?

A. As supported by my economic analysis, I recommend that the Commission determine that the decision to repower certain wind facilities is prudent and in the public interest and approve the Application as filed, including the request for continued cost recovery of the wind equipment that will be replaced and the proposed ratemaking treatment for the new costs and benefits of the wind repowering project.

Q. Does this conclude your direct testimony?

A. Yes.