REDACTED
Docket No. 20000-519-EA-17
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Rick T. Link

November 2017

Q. Are you the same Rick T. Link who previously provided direct testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. I summarize updates to the economic analysis that demonstrate increasing customer benefits from the wind repowering project. I also rebut challenges to the Company's economic analysis raised in the direct testimony of the Wyoming Industrial Energy Consumers ("WIEC") witness Mr. Kevin C. Higgins.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony summarizes updated and expanded economic analysis that incorporates modeling updates and new sensitivity studies developed in response to certain concerns raised by parties in this proceeding. My rebuttal testimony also addresses criticisms of PacifiCorp's modeling assumptions and methodologies. My rebuttal demonstrates that:

- The updated economic analysis shows net customer benefits in all of the scenarios analyzed.
- The wind repowering project will produce present-value net customer benefits, based on updated economic analysis over the remaining life of the repowered wind facilities, ranging between $360 million to $635 million.
- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.38 billion and $1.65 billion, which compares to present-value project costs totaling $1.02 billion.

- These net and gross customer benefits are conservative, as they do not account for additional incremental energy output that will be generated with the installation of equipment that only recently has been verified to be available for repowering of certain wind facilities.
- When measured over a 20-year period, the present value of net customer benefits from wind repowering range between $90 million and $214 million, which does not account for the value of incremental energy output that will increase significantly beyond 2036.
- Project-by-project analysis, provided in response to criticism by WIEC, confirms that the proposed scope of the project, including just over 999 megawatts ("MW") of existing wind resource capacity, is appropriate and will maximize customer benefits.
- Tax-policy sensitivity analysis, also provided in response to comments raised by WIEC, confirms that net customer benefits persist even with potential changes in the corporate federal income tax rate.
- The modeling tools and methodologies used to develop the economic analysis supporting the wind repowering project are robust.
- The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power costs, and deliver substantial federal production tax credit ("PTC") benefits that will be passed on to customers. The proposed wind repowering project is in the public interest.

MODELING UPDATES

Q. Did PacifiCorp update its economic analysis supporting the wind repowering project?

A. Yes. The economic analysis was updated to correct certain model inputs and to reflect more current assumptions.

Q. Please summarize these updates.

A. The models were updated to: (1) implement a correction to certain transmission assumptions; (2) reflect more current load-forecast assumptions; (3) reflect more current forward-price-curve assumptions; and (4) reflect more current cost-and-performance assumptions for the repowered wind facilities.

Q. Did you calculate how these updates impact the economic analysis that you summarized in your direct testimony?

A. Yes. PacifiCorp used the System Optimizer ("SO") model and the Planning and Risk model ("PaR") to determine the impact of these modeling updates on the economic analysis summarized in my direct testimony. These models were used to calculate how the present-value revenue requirement differential ("PVRR(d)") between a simulation with and without the wind repowering project changes after applying the modeling updates. The PVRR(d) calculated from the change in nominal revenue requirement due to wind repowering through 2050 was also calculated.

Q. What is the impact of these assumption changes in the economic analysis using medium natural gas prices and medium carbon dioxide ("CO_2") prices?

A. Based on SO model results through 2036, the expected wind repowering PVRR(d) benefits increase by $116.6 million, from $21.7 million as summarized in my direct testimony (Link Direct, Table 2) to $138.3 million. Based on stochastic-mean PaR results through 2036, the wind repowering PVRR(d) benefits increase by $101.8 million, from $13.5 million (Link Direct, Table 2) to $115.2 million. Based on nominal revenue requirement results through 2050, the PVRR(d) benefits of wind repowering increase by $112.5 million, from $358.7 million (Link Direct, Table 3) to $471.2 million. I describe each of these modeling updates in more detail below.

Q. Please describe the correction to transmission assumptions applied in the updated economic analysis.

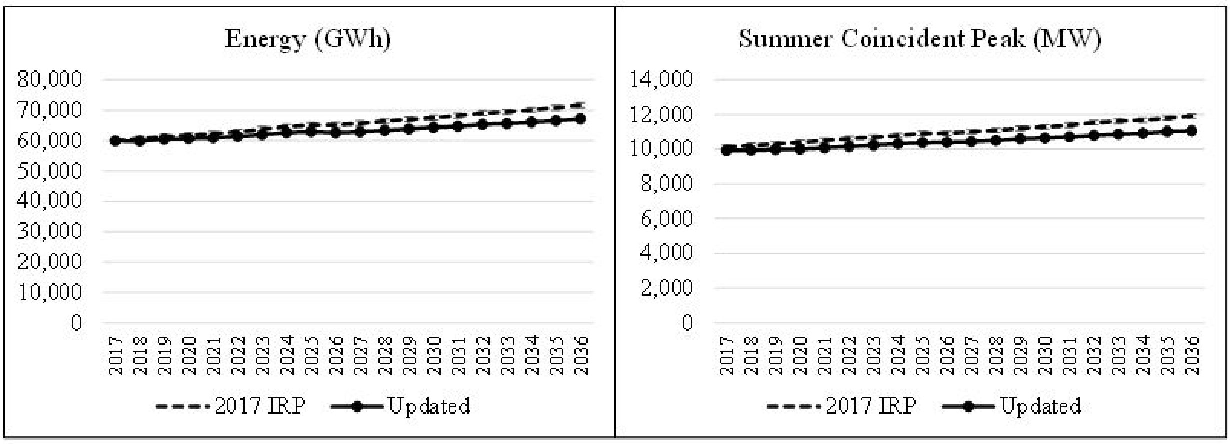
A. In my direct testimony, I described how PacifiCorp modeled de-rates to its Wyoming 230-kV transmission system. (Link Direct, page 15, lines -16-23 through page 16, lines 1-8.) Based on historical outage data, the transfer capability from eastern Wyoming to the Aeolus area was reduced by 36.5 MW in simulations that included the wind repowering project. This same de-rate was inadvertently not applied to the simulations that excluded the wind repowering project. This was corrected by applying the 36.5 MW transmission de-rate to simulations both with and without the wind repowering project.

Q. Please describe the new load forecast assumptions included in the updated economic analysis.

A. The load forecast used in the economic analysis summarized in my direct testimony is the same load forecast used in PacifiCorp's 2017 Integrated Resource Plan ("IRP"). This 2017 IRP load forecast was finalized in December 2016. My updated analysis uses the Company's new load forecast completed in the summer of 2017, after the Company made its initial filing.

Figure 1 compares the load forecast from the 2017 IRP used in my original economic analysis to the new load forecast. The updated system energy forecast is down by 2.2 percent in 2021 and down by 6.3 percent in 2036 relative to the 2017 IRP forecast. The updated coincident summer peak forecast is down by 4.1 percent in 2021 and down by 7.2 percent in 2036 relative to the 2017 IRP forecast.

Figure 1. Comparison of the 2017 IRP and Updated Load Forecast Assumption



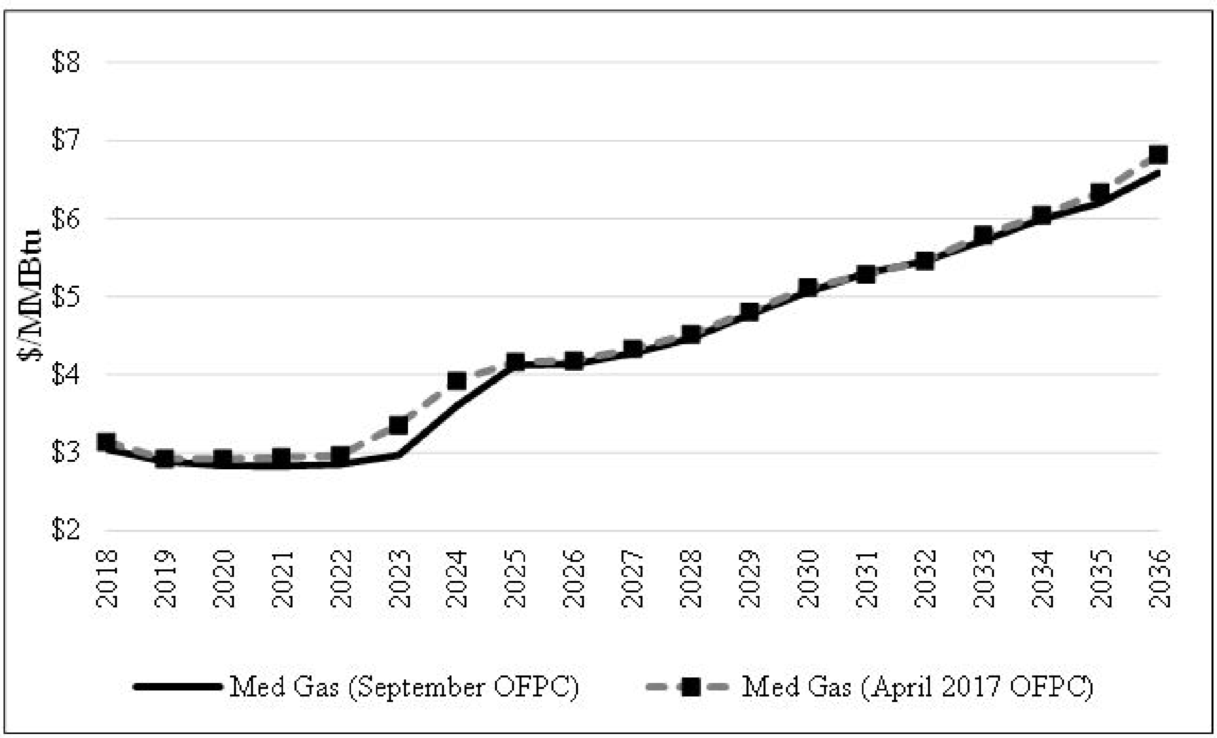
Changes in the load forecast are primarily driven by: (1) a reduction in Utah and Wyoming industrial loads principally due to reduced usage projections for a number of large customers; (2) increases in the growth of customer generation from 2017 to 2018, contributing to reductions in Utah residential customer usage; and (3) updated appliance saturation and efficiency assumptions with refinements to miscellaneous device sales data (i.e., televisions, pool heaters, personal computers, and other plug-in devices), contributing to reductions in Utah residential customer usage.

Q. Please describe the new price forecast included in the updated economic analysis.

A. In my direct testimony, I described nine price-policy scenarios, developed by pairing three natural-gas price forecasts (low, medium, and high) with three CO_2 price forecasts (zero, medium, and high). (Link Direct, page 23, lines 3-21.) The medium natural-gas price assumptions are derived from PacifiCorp's official forward price curve ("OFPC"). In the economic analysis summarized in my direct testimony, PacifiCorp used its April 26, 2017 OFPC.

PacifiCorp's most recent regular OFPC is dated September 30, 2017, which reflects more current market forwards and an updated forecast from IHS CERA. Figure 2 compares Henry Hub natural-gas prices from the April 26, 2017 OFPC, as used to support the economic analysis in my direct testimony, with Henry Hub natural-gas prices from the updated September 30, 2017 OFPC. Over the period 2018 through 2036, the nominal levelized price for Henry Hub natural-gas prices has dropped by approximately 2.6 percent from $4.07/MMBtu to $3.97/MMBtu. The reduction in levelized prices is primarily driven by reductions in the 2023 to 2024 time frame.

Figure 2. Comparison of the April 2017 and September 2017 OFPC Henry Hub Natural-Gas Price Forecasts



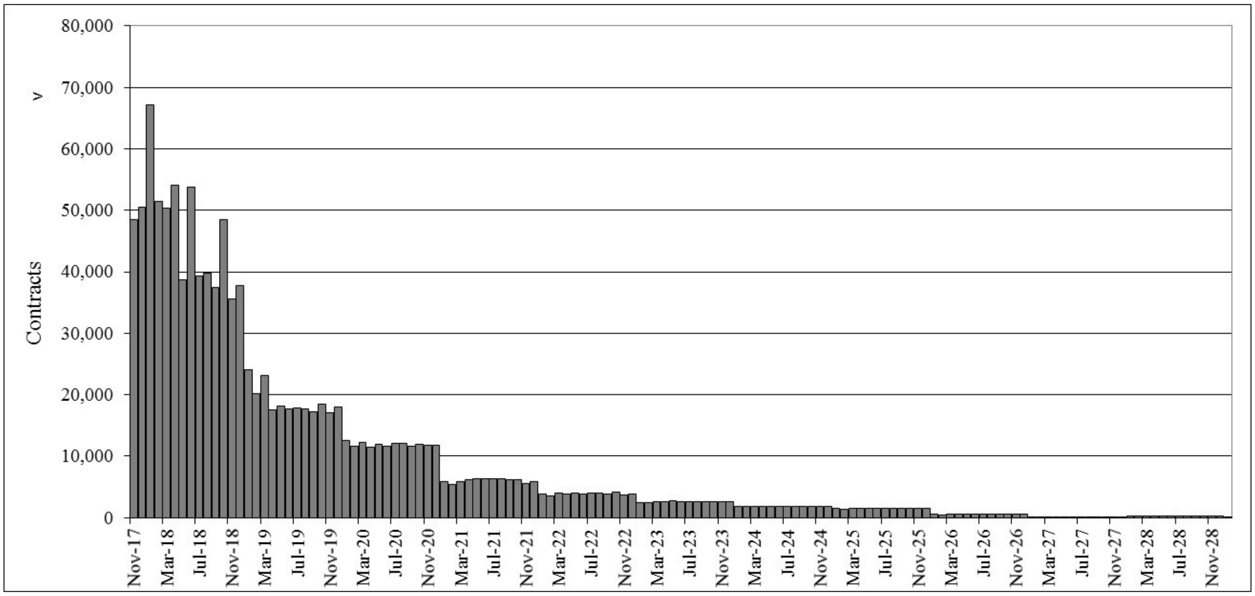
The updated OFPC reflects market forwards as of September 30, 2017, through October 2023. Prices in the updated market fundamentals forecast from IHS CERA, which are used exclusively in the OFPC beyond October 2024, track closely with those assumed in the April 2017 OFPC. PacifiCorp continues to blend market forwards from month 61 (November 2022) through month 72 (October 2023) with the fundamentals-based forecast from month 85 (November 2024) through month 96 (October 2025) to establish prices in month 73 (November 2023) through month 84 (October 2024).

Q. Mr. Higgins compares the Company's natural-gas price forecasts with NYMEX Henry Hub natural-gas futures through 2029 as of October 12, 2017, and concludes that this comparison demonstrates current market expectations most closely align with the Company's low natural-gas forecast. (Higgins Direct, page 13, lines 3-20.) How do you respond?

A. Mr. Higgins's conclusion is misguided because it relies solely on NYMEX Henry Hub natural-gas futures, which do not accurately capture market expectations for long-term natural-gas prices. Mr. Higgins fails to consider the open interest in NYMEX Henry Hub futures contracts, which quickly falls for futures contracts further out in time. The sparsity of open interest in the out period makes these futures contracts an unreliable indicator of market expectations for long-term natural-gas prices.

Each futures trade represents the creation of a new contract and is indicative of new capital being committed to the market. Figure 3 shows NYMEX Henry Hub natural-gas open interest as of October 12, 2017, which is the same quote date used by Mr. Higgins to compare NYMEX futures prices to the Company's Henry Hub natural-gas price forecast.

Figure 3. NYMEX Henry Hub Natural Gas Futures
Open Interest as of October 12, 2017



This figure shows that open interest is greater in the near term and significantly lower in the long term. For instance, in 2018 open contracts average over 46,100. By 2023, open contracts average just below 2,600, which is approximately six percent of the open interest observed for 2018 contracts. The concentration in the earlier futures indicates the market is deeper and stronger in the near term because fewer market participants are willing to commit capital required to enter and maintain long-term contracts.

There are very few contracts supporting NYMEX Henry Hub natural-gas-futures prices over the period in which Mr. Higgins claims the Company's low natural gas price scenario is most reflective of current gas market expectations (*i.e.*, beyond 2022). Contracts with greater open interest more accurately represent a market consensus of where spot prices are likely to trade. Long-term prices are shaped by a handful of participants who are lightly committed. These participants are basing their decisions on highly imperfect data. Short-term prices are shaped by a large field of market participants, who commit far more capital because there is more transparency around the conditions and variables that can impact prices.

Q. Did PacifiCorp update the low and high natural-gas price scenarios used in the economic analysis presented in your direct testimony?

A. No. Current low and high natural-gas price scenarios produced by third-party forecasters are not materially different than those used to support the economic analysis in my direct testimony. Similarly, there are no material changes in third-party forecasts for CO_2 price assumptions. Consequently, the low and high natural-gas price assumptions and the medium and high CO_2 price assumptions used in the economic analysis summarized in my direct testimony remain valid for testing how these variables impact the overall economics of the wind repowering project.

Q. Please describe the updated cost-and-performance assumptions for the repowered wind facilities.

A. As described in the rebuttal testimony of Company witness Mr. Timothy J. Hemstreet, General Electric ("GE") finished developing a 91-meter rotor for use in repowering wind facilities and has completed engineering and design review on a [redacted] turbine. Assuming the repowered wind facilities continue to operate within the limits specified in their large-generator interconnection agreements ("LGIAs"), the updated expected incremental energy output from wind repowering, accounting for use of the [redacted] turbines on GE sites (all but Marengo 1, Marengo 2, and Goodnoe Hills), is 25.9 percent (743 gigawatt-hour ("GWh") per year)—up from the 19.2 percent (551 GWh per year) increase assumed in my original economic analysis. Mr. Hemstreet also explains that the Company has fixed pricing for the wind repowering turbines supporting updated capital costs. The updated total up-front capital investment is $1.083 billion—a $45 million reduction from the cost assumed in my original economic analysis.

As noted by Mr. Hemstreet, the Company did not receive verification that the [redacted] turbine was technically suitable for GE sites within the scope of the repowering project until October 6, 2017. At this time, the Company had already begun updating its analysis assuming the use of a [redacted] turbine at GE sites. The longer blade length also improves expected incremental annual energy output relative to the [redacted] turbine equipment assumed in my original analysis. Assuming use of the [redacted] turbines, the updated incremental energy output is 24.9 percent (714 GWh per year)—up from the 19.2 percent (551 GWh per year) increase assumed in my original economic analysis. The updated total up-front capital investment assuming the use of [redacted] turbines on GE sites is $1.083 billion—identical to the up-front capital investment required assuming the use of [redacted] turbines on GE sites.

Because the Company did not receive verification that the [redacted] turbine was technically suitable for GE sites until after the updated economic analysis had been initiated, the bulk of my updated economic analysis assumes the use of [redacted] turbines on GE sites. However, now that the Company has received verification that the [redacted] turbines can be deployed on GE sites, I summarize the results of a sensitivity study that quantifies the incremental benefits from the use of this equipment later in my rebuttal testimony.

UPDATED SYSTEM-MODELING PRICE-POLICY RESULTS

Q. Did PacifiCorp update its system modeling among different price-policy scenarios to reflect the modeling updates described above?

A. Yes. Using the same system methodology described in my direct testimony, PacifiCorp updated the economic analysis for the wind repowering project, incorporating the modeling updates described earlier in my rebuttal testimony, including the assumed use of [redacted] turbines on GE sites. This updated analysis was performed using the SO model and PaR among nine different price-policy scenarios.

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

A. Table 1 summarizes the updated PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-R2).

Table 1. Updated 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	($110)	($90)	($95)
Low Gas, Medium CO_2	($125)	($108)	($113)
Low Gas, High CO_2	($133)	($114)	($119)
Medium Gas, Zero CO_2	($137)	($116)	($122)
Medium Gas, Medium CO_2	($138)	($115)	($121)
Medium Gas, High CO_2	($157)	($131)	($137)
High Gas, Zero CO_2	($196)	($152)	($160)
High Gas, Medium CO_2	($204)	($167)	($175)
High Gas, High CO_2	($214)	($167)	($176)

Over a 20-year period, before accounting for the increase in incremental energy output beyond 2036, the wind repowering project reduces customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits range between $115 million, when derived from PaR stochastic-mean results, and $138 million, when derived from SO model results.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

A. Projected system costs increase with high natural-gas price assumptions, and similarly, increase with high CO_2 price assumptions. Conversely, system costs decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Generally, this same trend applies when looking at the change in system costs between simulations with and without wind repowering. There are, however, a few exceptions. For example, in the medium natural-gas price scenarios where a change from a zero CO_2 price assumption to a medium CO_2 price assumption has a very marginal impact on the PVRR(d) benefits from repowering. In this price-policy scenario, the increase to system costs from PaR caused by the introduction of a CO_2 price assumption is slightly greater in the simulation without wind repowering than it is in the simulation with wind repowering.

These slight variations from expected trends can be explained by the difference in functionality between the SO model and PaR. Relative to the SO model, PaR provides additional granularity on how wind repowering is projected to affect system operations. However, in its optimization to minimize system costs, PaR cannot modify the resource portfolio, which is based on SO model results. This can contribute to variation in the trends observed between the two models as price-policy assumptions change across the scenarios. Importantly, both models, each having its own strengths, show that the wind repowering benefits are robust across a range of price-policy assumptions.

Q. Did you update the potential upside to these PVRR(d) results associated with renewable energy credit ("REC") revenues?

A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 1 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Accounting for the updated performance assuming use of [redacted] turbines on GE sites, customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2036 (up from $4 million in my original analysis).

Q. Is there additional upside to these PVRR(d) results?

A. Yes. The PVRR(d) results in Table 1 assume that [redacted] turbines are deployed on GE sites, not the [redacted] turbines now secured for these sites, which will deliver additional incremental energy output without any increase in cost. As described later in my rebuttal testimony, sensitivity analysis developed off of the medium natural-gas price and medium CO_2 price scenario that assumes the use of the [redacted] turbines improves the PVRR(d) benefits of wind repowering by $11 million to $13 million if these facilities continue operating within the limits specified in their LGIAs. If the LGIAs are modified to accommodate additional energy output, the incremental benefits of wind repowering increase by between $37 million to $48 million.

UPDATED REVENUE REQUIREMENT MODELING PRICE-POLICY RESULTS

Q. Did PacifiCorp update its revenue requirement modeling among different price-policy scenarios to reflect the modeling updates described above?

A. Yes. Using the same annual revenue requirement modeling methodology described in my direct testimony, PacifiCorp updated its forecast of the change in nominal annual revenue requirement due to the wind repowering project, incorporating the modeling updates described earlier my rebuttal testimony, including the assumed use of [redacted] turbines on GE sites.

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

A. Table 2 summarizes the updated 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-R3).

Table 2. Updated Nominal Revenue Requirement PVRR(d)
(Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($360)
Low Gas, Medium CO_2	($480)
Low Gas, High CO_2	($473)
Medium Gas, Zero CO_2	($483)
Medium Gas, Medium CO_2	($471)
Medium Gas, High CO_2	($534)
High Gas, Zero CO_2	($555)
High Gas, Medium CO_2	($635)
High Gas, High CO_2	($619)

When system costs and benefits from the wind repowering project are extended out through 2050, covering the full depreciable life of the repowered wind facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios. The PVRR(d) benefits range from $360 million in the low natural gas, zero CO_2 scenario to $635 million in the high natural gas, medium CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of wind repowering are $471 million.

Q. Is there potential upside to these PVRR(d) results associated with REC revenues?

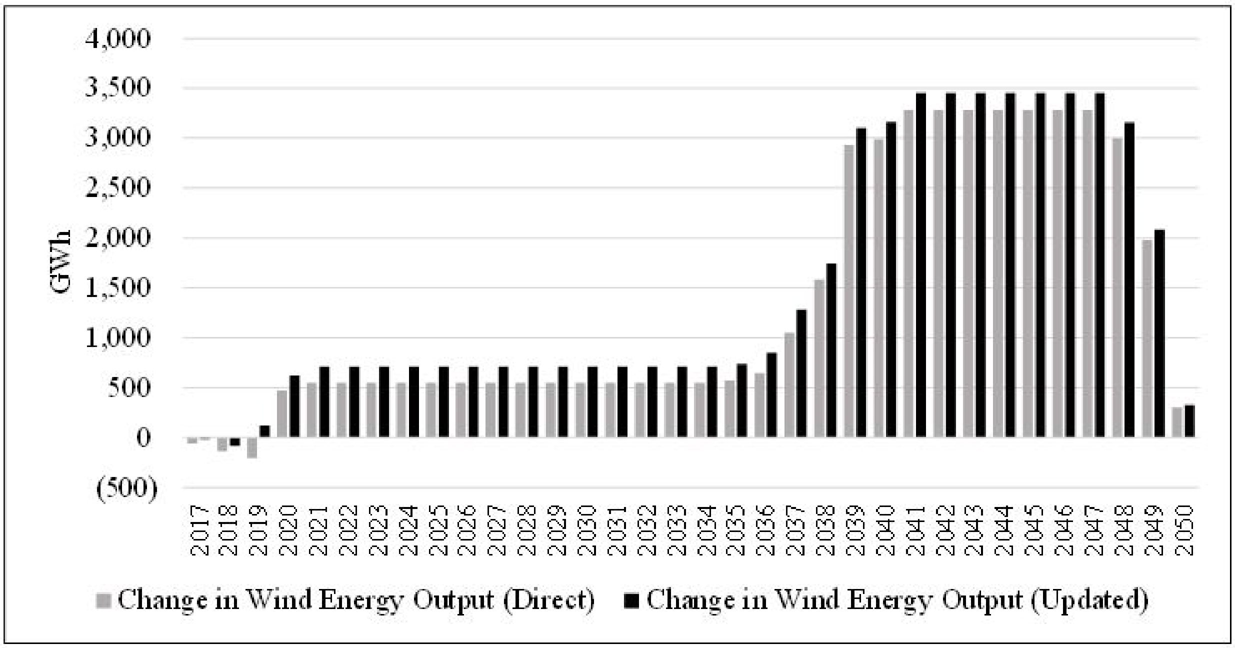
A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 2 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Accounting for the updated performance assuming use of [redacted] turbines on GE sites, customer benefits for all price-policy scenarios would improve by approximately $13 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2050 (up from $11 million in my original analysis). As noted earlier, quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits of wind repowering *could* improve *if* the incremental RECs can be monetized in the market.

Q. What causes the increase in PVRR(d) results when calculated off of the change in nominal revenue requirement through 2050 relative to the system modeling results calculated off of the change in system costs through 2036?

A. In my direct testimony, I explain that the extended analysis picks up the sizable increase in incremental wind energy output beyond the 20-year period analyzed with the SO model and PaR. (Link Direct, page 33, lines 4-20.) This same rationale applies to the economic analysis that has been refreshed to incorporate the modeling updates described earlier in my rebuttal testimony. In fact, with the increase in expected incremental energy output from the wind facilities, the change in incremental wind energy output is higher than what was assumed in the economic analysis summarized in my direct testimony.

Figure 4 shows the updated incremental change in wind energy output resulting from the repowering project alongside the same assumptions used in the economic analysis summarized in my direct testimony. The updated assumptions continue to show progressively higher levels of incremental energy output from 2036 through 2040, as wind facilities originally placed in service between 2006 and 2010 would have otherwise reached the end of their lives. Based on the updated assumptions, the average incremental increase in wind energy output is approximately 714 GWh. Beyond 2040, and before the new equipment reaches the end of its depreciable life, the average annual incremental increase in wind energy output is 3,454 GWh.

Figure 4. Comparison of the Updated Change in Incremental Wind Energy Output Due to Wind Repowering



Q. Mr. Higgins states that if the useful lives of the wind turbines are extended for an additional 10 years, then the benefits of repowering decrease. (Higgins Direct, page 16, lines 4-12.) How do you respond to this concern?

A. PacifiCorp's annual revenue requirement analysis, which extends the economic analysis beyond the 2036 time frame, captures the upside of increased incremental energy output beyond the period in which the repowered wind facilities would have otherwise reached the end of their depreciable lives. This analysis reasonably assumes that these facilities would be retired at the end of their current depreciable lives.

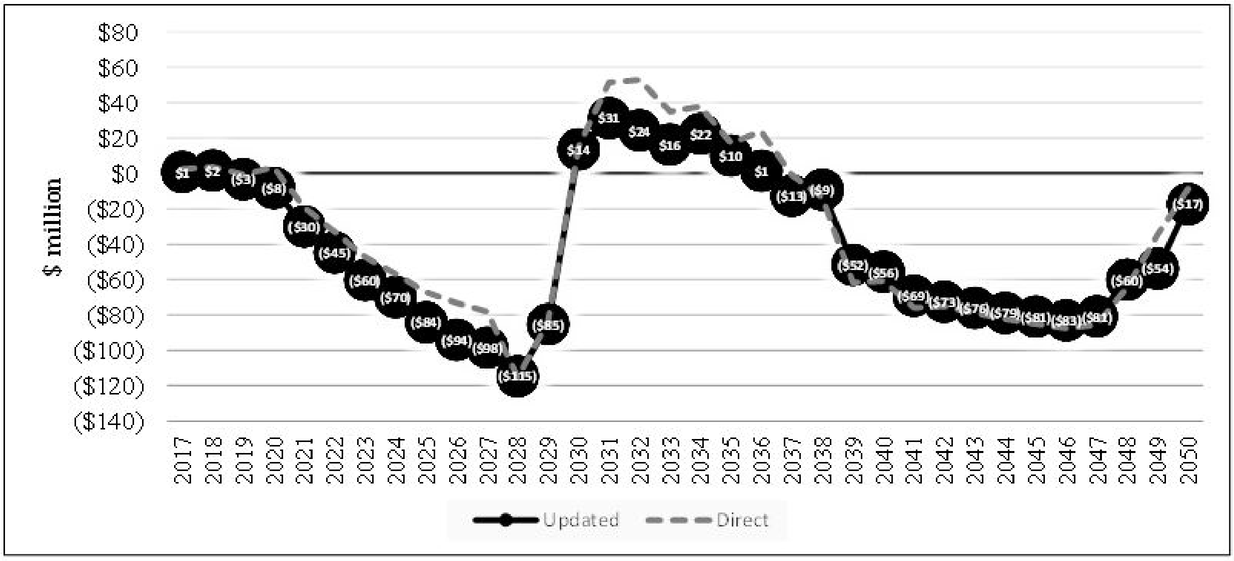
If one were to assume that the wind facilities would continue to operate for some period beyond their current depreciable lives if not repowered, it is reasonable to assume that the repowered wind facilities would also operate for some comparable period of time beyond their 30-year life initiated upon repowering.

The effect of this assumption would be to defer, but not eliminate, the value of the sizable increase in expected incremental energy beyond the assumed operable life of the wind facilities. Consequently, this would defer the associated incremental benefits beyond the assumed operable life of the wind facilities, which would be more heavily discounted in the present-value calculation. For this reason, it is no surprise that the PVRR(d) is reduced if one were to assume the existing wind facilities and the repowered wind facilities both continue to operate beyond their depreciable lives.

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

A. Figure 5 shows the updated change in nominal revenue requirement due to wind repowering for the medium natural gas, medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects updated 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 updated system impacts from wind repowering, reflecting the change in net power cost ("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. Updated Total-System Annual Revenue Requirement
With Wind Repowering ($ million)



This figure has the same basic profile as Figure 5 from my direct testimony. This profile shows substantial near-term benefits associated with the PTCs, a period over which the change in annual revenue requirement increases after the PTCs expire, and a period over the long term where the change in annual revenue requirement is reduced based on substantial and progressively growing increases to incremental energy output between 2036 through 2041. The PVRR(d) benefits from the wind repowering project calculated off of this stream of data is $471 million—the same figure shown in Table 2 for the medium natural gas, medium CO_2 price-policy scenario.

PROJECT-BY-PROJECT ANALYSIS

Q. Did WIEC raise concerns about the scope of the proposed wind repowering project?

A. Yes. Mr. Higgins faults PacifiCorp for modeling repowering as a single project, instead of modeling each facility individually, and states that the incremental benefits being contributed by the Leaning Juniper and Goodnoe Hills facilities suggests that the collective benefit from the remaining sites under the medium gas, medium CO_2 scenario could be negative. (Higgins Direct, page 29, lines 11-17.)

Q. Is it true that some of the individual facilities are not economic to repower?

A. No. In response to the concerns raised by Mr. Higgins, PacifiCorp developed a series of studies using the SO model and PaR to analyze the net benefits of each individual wind facility included in the proposed scope of the wind repowering project. This is a more robust analytical approach that accounts for how each repowered wind facility interacts with the broader system.

Q. Please describe how you developed this project-by-project analysis.

A. The methodology used to develop the project-by-project analysis is similar to the methodology used to perform the economic analysis for the proposed wind repowering project. Assuming medium natural gas and medium CO_2 price-policy assumptions, PacifiCorp ran two SO model simulations for each of the 12 wind facilities within the scope of the proposed wind repowering project—one simulation in which all 12 facilities within the proposed scope are repowered and one simulation that assumes one of the 12 wind facilities is not repowered. For each simulation, the difference in projected system costs from the SO model, accounting for any changes to the resource mix over a 20-year forecast period, are used to calculate the marginal PVRR(d) for each wind facility.

Using the resource portfolios from the SO model simulations, this same approach was used to calculate PVRR(d) for each wind facility using projected system costs from PaR over a 20-year forecast period. Finally, the SO model and PaR model results are used to estimate the change in nominal annual revenue requirement for each wind facility by extending the system modeling results to 2050. The methodology used to estimate the change in nominal annual revenue requirement through 2050 is identical to the methodology used to analyze the full scope of the wind repowering project.

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

A. Table 4 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and for PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering.

Table 4. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($17)	($14)	($14)
Glenrock 3	($5)	($3)	($4)
Seven Mile Hill 1	($23)	($20)	($21)
Seven Mile Hill 2	($5)	($5)	($5)
High Plains	($4)	($1)	($1)
McFadden Ridge	($1)	($0)	($0)
Dunlap Ranch	($14)	($11)	($11)
Rolling Hills	($5)	($3)	($3)
Leaning Juniper	($3)	($3)	($4)
Marengo 1	($28)	($26)	($27)
Marengo 2	($10)	($9)	($10)
Goodnoe Hills	($21)	($21)	($22)
Total	($138)	($117)	($122)

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

A. Table 5 summarizes the PVRR(d) results for each wind facility calculated off of the change in annual nominal revenue requirement through 2050. Unlike the results summarized in Table 4, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering.

Table 5. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Annual Revenue Requirement PVRR(d)
Glenrock 1	($50)
Glenrock 3	($15)
Seven Mile Hill 1	($65)
Seven Mile Hill 2	($17)
High Plains	($37)
McFadden Ridge	($11)
Dunlap Ranch	($60)
Rolling Hills	($30)
Leaning Juniper	($34)
Marengo 1	($77)
Marengo 2	($30)
Goodnoe Hills	($50)
Total	($477)

Q. Why is the sum of the project-by-project PVRR(d) results summarized in Tables 4 and 5 not precisely equal to the comparable scenario results shown in Tables 1 and 2 of your rebuttal testimony?

A. The scope of the wind repowering project is similar, yet unique, for each of the studies summarized in these tables. Eliminating one of the wind facilities from the scope of repowering project affects how the remaining repowered facilities contribute to the forecasted system costs and benefits of repowering. The impact on system costs that results from altering the scope of the repowering project varies depending upon the specific characteristics of the wind facility being studied. For this reason, it is reasonable to expect that the sum of the project-by-project results in Tables 4 and 5 are not precisely equal to the comparable scenario results in Tables 1 and 2.

Q. The project-by-project results vary by wind facility, and some wind facilities appear to show relatively small PVRR(d) benefits. Do these results support eliminating those or any other facility from the scope of the wind repowering project?

A. No. The magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows an $11 million benefit when repowered-the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is 14 percent of the $77 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, current capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the current capacity for Marengo 1 (140.4 MW). Similarly, the expected energy output after repowering for McFadden Ridge (approximately 108 GWh per year) is approximately 22 percent of the expected energy output after repowering for Marengo 1 (approximately 408 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental megawatt-hour ("MWh") expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 6 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. The table shows the Seven Mile Hill 2 facility produces the largest net benefit per incremental MWh and Leaning Juniper produces the smallest net benefit per incremental MWh. All facilities produce net benefits equal to or greater than $27/MWh of incremental energy output after repowering.

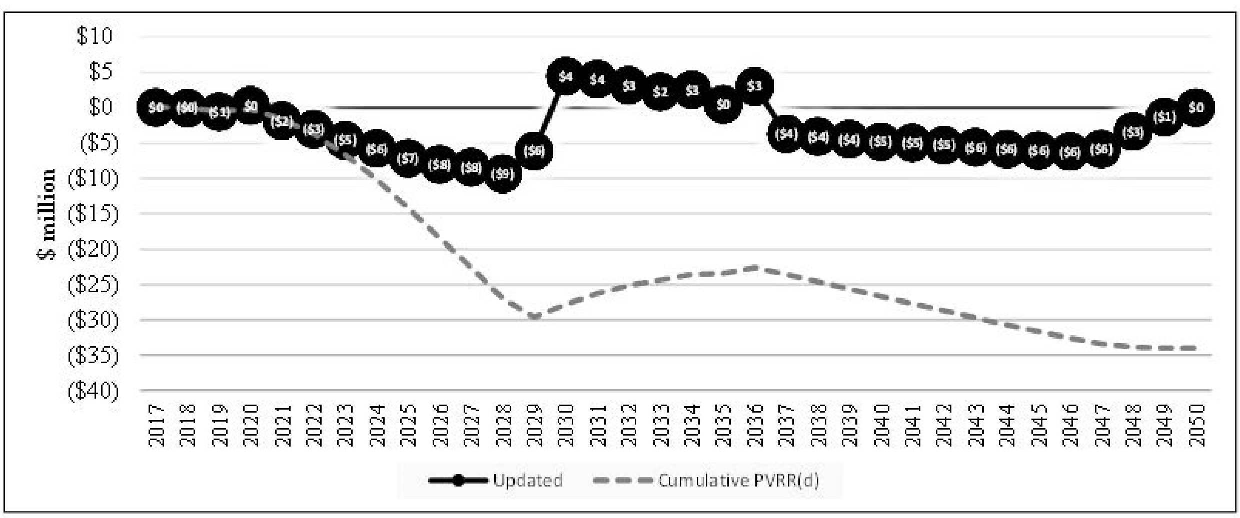
Table 6. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh)

Wind Facility	Nominal Levelized Net Benefit
Glenrock 1	$43/MWh
Glenrock 3	$39/MWh
Seven Mile Hill 1	$46/MWh
Seven Mile Hill 2	$58/MWh
High Plains	$29/MWh
McFadden Ridge	$28/MWh
Dunlap Ranch	$42/MWh
Rolling Hills	$36/MWh
Leaning Juniper	$27/MWh
Marengo 1	$37/MWh
Marengo 2	$31/MWh
Goodnoe Hills	$47/MWh

Q. Have you reviewed the change in annual nominal revenue requirement due to wind repowering from the Leaning Juniper facility, which yields the lowest net benefits per MWh of incremental energy output among all facilities within the proposed scope of repowering project?

A. Yes. Figure 6 shows the change in nominal revenue requirement due to wind repowering for the Leaning Juniper wind facility. The figure also shows the cumulative PVRR(d) for Leaning Juniper through 2050. The cumulative PVRR(d) for any given year reflects the present value net benefits from prior years that are associated with repowering Leaning Juniper. For instance, the cumulative PVRR(d) shown for 2020 represents the present value of the net benefits for repowering over the period 2017 through 2020. Consequently, the cumulative PVRR(d) in 2050 captures the net benefits of repowering the Leaning Juniper wind facility through its expected useful life (*i.e.*, $34 million of net benefit as reported in Table 5).

Figure 6. Total-System Annual Revenue Requirement for Leaning Juniper with Wind Repowering ($ million)



As is the case with the projected change in nominal revenue requirement for the all projects in the wind repowering scope presented in Figure 5, this figure shows that repowering Leaning Juniper will produce substantial near-term customer benefits, followed by a period in which the change in annual revenue requirement exhibits a moderate increase after the PTCs expire. In 2037 and beyond, the change in annual revenue requirement is reduced due to the substantial increase in incremental energy output beyond the period in which Leaning Juniper would have otherwise reached the end of its useful life (*i.e.*, increasing from approximately 70 GWh before 2037 to just under 304 GWh beyond 2037).

Importantly, with the substantial cost savings associated with the PTCs over the first 10 years after repowering, the cumulative PVRR(d) reaches $30 million by 2029—approximately 87 percent of the PVRR(d) benefits calculated off the change in nominal system costs through 2050. The cumulative PVRR(d) benefits decline after the PTCs expire, but when Leaning Juniper would have otherwise reached the end of its useful life in 2036, wind repowering still yields cumulative PVRR(d) benefits totaling $23 million. Even if one were to assume that there is *no* net incremental benefit associated with the incremental energy output expected from Leaning Juniper beyond 2036, the net benefits of repowering this facility, which yields the lowest nominal levelized net benefit per MWh of incremental energy among all of the wind facilities within the scope of the repowering project, would still generate net customer benefits totaling $23 million on a present-value basis.

Q. What do you conclude from this project-by-project analysis?

A. The project-by-project analysis demonstrates that the proposed scope of the wind repowering project, which includes repowering 12 wind facilities with a current capacity totaling just over 999 MW is appropriate and will maximize customer benefits.

This is a conservative analysis because the project-by-project analysis evaluates the GE projects using lower generation output from [redacted] turbines, not the higher output expected from the [redacted] turbines the Company has now secured.

TAX POLICY SENSITIVITY

Q. Mr. Higgins states that a change in corporate tax rates could have a significant impact on the viability of this project. (Higgins Direct page 25, lines 19-20.) Please respond.

A. The potential changes, if any, to the federal corporate income tax rate are highly uncertain. For this reason, I did not include a sensitivity in my original analysis to account for speculative tax rate changes. While this issue remains uncertain, to respond to Mr. Higgins' concerns, I have performed a sensitivity analysis that assumes a lower federal corporate tax rate to determine how that lower rate impacts the economic benefits from the wind repowering project.

Q. Please describe the corporate tax rate assumption used for this sensitivity analysis.

A. For purposes of the tax policy sensitivity, PacifiCorp assumes the current federal income tax rate is decreased from 35 percent to an effective rate of 25 percent. The basis for this assumed reduction is provided in the rebuttal testimony of Company witness Ms. Nikki L. Kobliha. Assuming a marginal state income tax rate of 4.54 percent less a federal deductibility benefit of 1.135 percent, the assumed net state tax rate is 3.405 percent. Based on these inputs, the effective combined federal and state income tax rate assumed for this sensitivity is 28.405 percent.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and PaR for this sensitivity.

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital ("post-tax WACC"), which is used as the discount rate in the SO model and PaR. Assuming no change to the corporate tax rate, the discount rate assumed in the benchmark economic analysis is 6.57 percent. Assuming a drop in effective combined federal income tax rate from 37.951 percent to 28.405 percent for purposes of this sensitivity increases the discount rate to 6.81 percent. This modified discount rate assumption is used in both the SO model and PaR for each simulation of PacifiCorp's system-simulations with and without wind repowering.

The modified income tax rate assumed for this sensitivity also affects the capital revenue requirement for all new resource options available for selection in the SO model. As described in my direct testimony, capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. (Link Direct, page 18, lines 16-23 through page 19, lines 1-12.) This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for a specific types of assets, are differentiated by each asset's assumed life, book depreciation rates, and tax depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were updated for each simulation of PacifiCorp's system-simulations with and without wind repowering.

Finally, the modified income tax rate assumption affects the tax gross-up of all PTC-eligible resources. As noted in my direct testimony, the current value of federal PTCs is $24/MWh, which equates to a $38.68/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 37.95 percent. (Link Direct, page 5, lines 6-10.) If the effective combined federal and state income tax rate were reduced to 28.405 percent, the reduction in revenue requirement associated with federal PTCs would drop from $38.68/MWh to $33.52/MWh, adjusted for inflation over time. The impact of the modified income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model in the simulations with and without wind repowering. The adjustment to the reduction in revenue requirement associated with federal PTCs was also applied to repowered wind facilities in the simulation with repowering.

Q. Please summarize the results of the tax policy sensitivity.

A. Table 7 summarizes the results of the sensitivity that assumes the corporate federal income tax rate is reduced from 35 percent to 25 percent. To assess the potential impact of a change in the federal corporate tax rate, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the comparable benchmark study in which it is assumed the federal corporate income tax rate is not changed. The sensitivity results reflect medium natural gas and medium CO_2 price-policy assumptions.

Table 7. Tax Policy Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model Through	($45)	($138)	$93
PaR Stochastic Mean	($23)	($115)	$93
PaR Risk Adjusted	($24)	($121)	$97

Q. What do you conclude from the tax policy sensitivity results?

A. Although the overall benefit of the wind repowering project is reduced by between $93 million to $97 million, the wind repowering project still produces net economic benefits for customers.

PROJECT EQUIPMENT SENSITIVITY

Q. Did you perform a sensitivity study to evaluate the upside benefits of the wind repowering project assuming use of the [redacted] turbines on repowering sites that will use GE equipment?

A. Yes. As described earlier in my rebuttal testimony, after initiating the updated analysis assuming use of [redacted] turbines, PacifiCorp received verification that the [redacted] turbines are technically feasible for wind repowering at wind repowering sites that will use GE equipment. Assuming repowered wind facilities continue to operate within the limits of their LGIAs, this will increase incremental annual energy output for the wind repowering project by 25.9 percent (743 GWh per year)—up from the 24.9 percent (714 GWh per year) assumed in my updated economic analysis. This equipment can be deployed without any incremental cost.

Q. Please summarize the results of this sensitivity.

A. Table 8 summarizes the results of the sensitivity that assumes [redacted] turbines are deployed on wind repowering sites that will use GE equipment. To assess the potential impact of deploying this equipment, the PVRR(d) was calculated through 2036 based on the SO model and PaR, and these results are presented alongside the comparable benchmark study which assumed use of [redacted] turbines. The sensitivity reflects medium natural gas and medium CO_2 price-policy assumptions and shows that the benefits of deploying the [redacted] turbines range between $11 million to $13 million before accounting for the sizable increase to incremental energy output from the repowered wind projects beyond 2036.

Table 8. LGIA-Limited Equipment Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model Through	($152)	($138)	($13)
PaR Stochastic Mean	($127)	($115)	($11)
PaR Risk Adjusted	($132)	($121)	($11)

Q. Did you also analyze the upside benefits based on the [redacted] turbines assuming the LGIAs for the repowered wind facilities can be modified to accommodate additional output from the wind repowering project?

A. Yes. If the LGIAs can be modified to allow all of the turbines to operate up to their full nameplate capability, the incremental annual energy output from repowered wind facilities will increase by 30.0 percent (862 GWh per year)—up from the 24.9 percent (714 GWh per year) assumed in my updated economic analysis. As explained in the rebuttal testimony of Mr. Hemstreet, this scenario would require replacing turbine pad-mount transformers, upgrading some segments of collector systems, and retrofitting or replacing certain generator step-up transformers for an incremental combined cost of

$36 million.

Q. Please summarize the results of this sensitivity.

A. Table 9 summarizes the results of the sensitivity that assumes use of [redacted] turbines with modified LGIAs. To assess the potential impact of deploying this equipment, the PVRR(d) was calculated through 2036 based on the SO model and PaR, and these results are presented alongside the comparable benchmark study which assumed use of [redacted] turbines. The sensitivity reflects medium natural gas and medium CO_2 price-policy assumptions and shows that the benefits of deploying the [redacted] turbines with modified LGIAs range between $37 million to $48 million before accounting for the sizable increase to incremental energy output from the repowered wind projects beyond 2036.

Table 9. LGIA-Modified Equipment Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model Through	($186)	($138)	($48)
PaR Stochastic Mean	($153)	($115)	($37)
PaR Risk Adjusted	($160)	($121)	($39)

GENERAL MODELING ASSUMPTIONS

Q. Mr. Higgins states that there is no indication that the current administration or Congress are inclined to implement CO_2 uplift costs and the scenarios with zero carbon price are most reflective of current expectations. (Higgins Direct, page 13, lines 4-7.) Do you agree?

A. No. It is simply not reasonable to conclude that today's policy environment is the best indicator of the policy environment we can expect over the next three decades. It is even more unreasonable to dismiss the results of scenarios developed to quantify the economic impact of potential environmental policy outcomes that could impute a financial cost on CO_2 emissions at some point over the next three decades. While it is *possible* that no such policy will materialize, as contemplated in certain price-policy scenarios, it does not mean that given the current policy environment, it is the *most likely* scenario.

Q. Mr. Higgins also provides a sensitivity analysis for a one-percent reduction in generation and alleges that under performance could be material for both PTC benefits and for the customer benefit of displacing more expensive variable-cost energy. (Higgins Direct, page 26, lines 15-20 through page 27, lines 1-12.) How do you respond?

A. Mr. Higgins calculates the potential impact on the PVRR(d) value of federal PTC benefits assuming a one-percent reduction in generation from the repowered wind facilities. PacifiCorp's wind generation forecast for the repowered wind facilities is derived by applying the incremental increase in energy output calculated from actual operating data to the actual historical wind generation from each wind facility since it was originally placed in service. Because this forecast is tied to actual generation and actual turbine output data resulting from the actual experienced wind conditions at the existing wind facilities, I have a high degree of confidence in the generation forecasts used in the economic analysis.

Mr. Higgins does not testify that PacifiCorp's wind generation forecasts are invalid. He simply asserts that there is potential risk to the overall economics of the wind generation output were reduced by one percent. This one-sided risk assessment fails to quantify the potential upside benefits if wind generation exceeds the assumed forecast used in the economic analysis by one percent. Using Mr. Higgins' calculations, the PVRR(d) benefits calculated from the change in system costs through 2050 assuming medium natural-gas price and medium CO_2 price-policy assumptions would be reduced from $471 million to $462 million if wind generation data were one percent lower than assumed and be increased from $471 million to $480 million if wind generation data were one percent higher than assumed.

CONCLUSION

Q. Please summarize the conclusions of your rebuttal testimony.

A. The updated economic analysis summarized in my rebuttal testimony supports repowering just over 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The updated economic analysis shows significant net customer benefits in all of the scenarios analyzed. The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power costs, and deliver substantial federal PTC benefits that will be passed on to customers. The proposed wind repowering project is in the public interest.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AN ORDER APPROVING NONTRADITIONAL RATEMAKING RELATED TO WIND REPOWERING)))))	DOCKET NO. 20000-519-EA-17 (RECORD NO. 14780)

AFFIDAVIT, OATH AND VERIFICATION

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

Affiant is the Vice President Resource and Commercial Strategy for PacifiCorp, which is a party in this matter.

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

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

Further Affiant Sayeth Not.

Dated this 14th day of November, 2017

Rick T. Link
Vice President, Resource and
Commercial Strategy
825 NE Multnomah
Portland, OR 97232

STATE OF UTAH)
) SS:
COUNTY OF SALT LAKE)

The foregoing was acknowledged before me by Rick T. Link on this 14th day of November, 2017. Witness my hand and official seal.

Melanie R. Allen

Notary Public

My Commission Expires:

MELANIE R ALLEN
NOTARY PUBLIC - STATE OF UTAH
My Comm. Exp. 09/11/2018
Commission # 679269