REDACTED
Rocky Mountain Power
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Direct and Rebuttal Testimony of Rick T. Link

January 2018

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

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental direct and rebuttal testimony?

A. In my supplemental direct testimony, I summarize the results of the 2017R Request for Proposals ("RFP"). I also provide updates to the economic analysis that demonstrate increasing customer benefits from the new wind resources ("Wind Projects") and construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects").

In my rebuttal testimony, I rebut challenges to the company's economic analysis raised in the direct testimonies of the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni Zenger and Daniel Peaco; Office of Consumer Services ("OCS") witnesses Philip Hayet and Bela Vastag; and the Utah Association of Energy Users and Utah Industrial Energy Consumers ("UAE/UIEC") witness Bradley G. Mullins.

Q. Please summarize your supplemental direct testimony.

A. The 2017R RFP generated robust and competitive responses from market participants. The final shortlist includes four new wind projects located in Wyoming from three different bidders. The total capacity of the four projects is 1,170 MW including three of the benchmark facilities (TB Flats I and II, now combined as a single project, and McFadden Ridge II), and two new facilities (Cedar Springs and Uinta). Uinta is a build-transfer agreement ("BTA") totaling 161 MW, Cedar Springs is one-half BTA and one-half power-purchase agreement ("PPA"), for a total of 400 MW, and TB Flats I and II and McFadden Ridge II are company-built facilities, totaling 500 MW and 109 MW, respectively.

The results of the 2017R RFP and the extensive modeling that supports it confirm that the Combined Projects are the least-cost, least-risk path available to serve the company's customers by meeting both near-term and long-term needs for additional resources. My supplemental direct testimony explains the following:

- The Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $177 million in the medium case through 2050 (as compared to $137 million in the original filing), and range from $311 million to $343 million in the medium case through 2036.
- The analysis reflects changes in federal tax law that were enacted in December 2017, and updated best-and-final pricing from bidders received December 21, 2017, after the federal tax law changes were known.
- The treatment of production tax credits ("PTCs") in the system modeling scenarios extending out through 2036 has been changed to better reflect how the PTCs will flow through to customers, which makes the treatment consistent with the nominal revenue requirement results that extend out through 2050.
- Sensitivity analysis shows substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced when considering the potential procurement of solar PPA bids submitted into the on-going RFP for solar resources, the 2017S RFP.

Q. Please summarize your rebuttal testimony.

A. I address criticisms of the Company's modeling assumptions and methodologies used to develop the economic analysis supporting the Combined Projects. My rebuttal testimony demonstrates that:

- PacifiCorp has near-term and long-term resource needs that will be partially met with the proposed Wind Projects.
- The heavily discounted cost of the Wind Projects is lower cost than all other near-term and long-term resource alternatives.
- Contrary to certain parties' claims, there is nothing novel or unique about the Combined Projects that justifies unprecedented cost-recovery treatment that assigns all risk to the company.
- PacifiCorp's long-standing methodology to develop its official forward price curve ("OFPC") produces the best representation of future market prices and is appropriately used for the central forecast in the company's economic analysis; the alternative price-policy scenarios provide a reasonable foundation for judging risk.
- The company's economic analysis appropriately addresses key project risks that support including the Combined Projects as an important element in PacifiCorp's least-cost, least-risk resource plan.

SUPPLEMENTAL DIRECT TESTIMONY

2017R RFP RESULTS

Q. When did PacifiCorp issue the 2017R RFP?

A. PacifiCorp issued the 2017R RFP on September 27, 2017, after it was approved by the

Public Service Commission of Utah ("Commission") on September 22, 2017, and the Public Utility Commission of Oregon ("Oregon Commission") on September 27, 2017.

Q. Was the scope of the 2017R RFP modified before it was issued to include non-Wyoming wind projects?

A. Yes. The company's original proposal limited the RFP to wind resources capable of interconnecting to or delivering on a firm basis to the company's transmission system in Wyoming. In response to issues raised in the RFP approval process, and consistent with the recommendations of Merrimack Energy Group, Inc., the Utah independent evaluator ("IE"), the company expanded the 2017R RFP to allow bids from non-Wyoming wind projects capable of interconnecting to or delivering on a firm basis to anywhere on the company's transmission system.

Q. In response to the Commission's approval order, did the company decide to issue a solar RFP to run concurrently with the 2017R RFP?

A. Yes. In its order approving the 2017R RFP, the Commission suggested, but did not require, a modification to expand the 2017R RFP to solicit solar resource bids. To maintain the 2017R RFP schedule while addressing the Commission's suggestion, the company issued a separate solicitation process for solar resources, the 2017S RFP, on November 15, 2017. The 2017S RFP sought bids for solar resources up to 300 MW per individual project that can deliver energy and capacity to the company's transmission system.

Similar to the 2017R RFP, the company retained London Economics International, LLC ("Solar RFP IE") as the IE to oversee the solar RFP process. The 2017S RFP schedule allowed the company to: (1) evaluate how solar resource bids might impact the economic analysis of bids selected to the final shortlist in the 2017R RFP without delaying the schedule for the 2017R RFP; and (2) explore whether new solar resource opportunities might provide all-in economic benefits for customers.

Q. When did the company receive initial bids in the 2017R RFP?

A. The company received initial bids for Wyoming wind projects on October 17, 2017, and initial bids for non-Wyoming wind projects on October 24, 2017. The 2017R RFP was well received by the market, as indicated by the fact the company received Wyoming wind proposals from nine bidders offering 49 bid alternatives for 13 wind projects. The company also received non-Wyoming wind proposals from five bidders offering 15 bid alternatives for six wind projects. In aggregate, 5,219 MW of new wind resource capacity was bid into the 2017R RFP (4,624 MW of Wyoming wind and 595 MW of non-Wyoming wind).

Q. When did the company complete its initial shortlist evaluation?

A. The company completed its initial shortlist evaluation and scoring and began a capacity factor evaluation process, performed by Sapere Consulting, on November 12, 2017. The Utah IE and Bates White, LLC, the Oregon IE, completed their review of the initial shortlist on November 17, 2017. Once the IEs completed their review of the initial shortlist, the company notified bidders whether their proposed projects were selected to the initial shortlist and provided an opportunity for bidders selected to the initial shortlist to update pricing. On November 22, 2017, the company received best-and-final pricing for bids selected to the initial shortlist.

Q. Did the company use the best-and-final pricing received on November 22, 2017, to establish the 2017R RFP final shortlist?

A. No. On November 16, 2017, shortly after best-and-final pricing was received, the U.S. House of Representatives passed H.R. 1, which included changes in federal tax law reasonably expected to affect bid pricing. On December 2, 2017, the U.S. Senate passed its own version of a tax-reform bill, setting the stage for a conference committee to reconcile differences between the two bills. On December 7, 2017, the company notified bidders that it would request updated pricing to reflect potential changes in federal tax law once the reconciliation process initiated by Congress was completed. On December 15, 2017, the conference committee approved its report on H.R. 1, and on December 18, 2017, the company notified bidders that updated best-and-final pricing reflecting federal tax provisions outlined in the conference committee's report on H.R. 1 must be submitted by December 21, 2017. The updated best-and-final pricing received on December 21, 2017, was used to establish the 2017R RFP final shortlist.

Q. Were the provisions in the conference committee's report on H.R. 1 ultimately passed by Congress and signed by the President?

A. Yes. Congress passed H.R. 1 on December 20, 2017. The bill became law on December 22, 2017, when it was signed by President Trump.

Q. How did the company select which bids to include in the 2017R RFP final shortlist?

A. Consistent with the bid evaluation and selection process outlined in the Commission-approved RFP, the final shortlist selection process was implemented in two basic phases--the portfolio-development phase and the scenario-risk phase.

Q. Please describe the portfolio-development phase.

A. The portfolio-development phase identifies the least-cost combination of bids using a methodology that is consistent with the approach used to produce resource portfolios in the integrated resource plan ("IRP"). The portfolio-development phase was initiated by processing best-and-final pricing for each bid into the cost-and-performance data required as inputs to the System Optimizer ("SO") model and the Planning and Risk model ("PaR").

The SO model was then used to develop bid portfolios containing the least-cost combination of bids over a twenty-year planning horizon (2017 through 2036). When choosing the least-cost combination of bids, the SO model was configured to select from all of the bids and bid alternatives included in the initial shortlist and all other proxy-resource alternatives used to develop resource portfolios in PacifiCorp's 2017 IRP (*i.e.*, front-office transactions or "FOTs", demand-side management resources, new thermal resources, *etc.*). The company did not force the SO model to select any bid or any combination of bids.

The company developed bid portfolios for nine price-policy scenarios, which, as described in my direct testimony, are developed by pairing three natural-gas price forecasts (low, medium, and high) with three carbon dioxide ("CO_2") price forecasts (zero, medium, and high). I describe updates made to these price-policy scenarios since the company's original filing later in my supplemental direct testimony.

For each price-policy scenario, the company also calculated the present-value revenue-requirement differential ("PVRR(d)") between two system simulations--one that includes 2017R RFP bids and the Transmission Projects and one without. These studies were prepared using the SO model and PaR and are used to quantify the economic impact of top-performing bid portfolios.

The combination of bids selected by the SO model across each of the nine price-policy scenarios and the accompanying PVRR(d) results, calculated using the SO model and PaR, identifies the bid portfolios expected to deliver economic benefits for customers. Specific to the 2017R RFP, this process identified two bid portfolios that were then further evaluated in the scenario-risk analysis phase of the bid-selection process.

Q. When developing bid portfolios, how much new wind capacity could the SO model select in eastern Wyoming?

A. Consistent with the assumptions in my direct testimony, the company assumed that the Aeolus-to-Bridger/Anticline transmission line will enable interconnection of up to 1,270 MW of additional wind resources to PacifiCorp's transmission system in eastern Wyoming. Considering that there is a transmission customer in the interconnection queue with an executed interconnection agreement for a 240-MW qualifying facility ("QF") in the area, the company assumed that sufficient interconnection capacity must be reserved for this transmission customer. Consequently, the company restricted new wind resource bids in eastern Wyoming to 1,030 MW (1,270 MW less 240 MW).

Q. Please describe the scenario-risk-analysis phase of the final shortlist bid-evaluation process.

A. The scenario-risk phase of the bid-evaluation process ensures that the two top-performing bid portfolios identified in the portfolio-development phase of the selection process are analyzed among all nine price-policy scenarios. For instance, one of the bid portfolios identified in the portfolio-development phase includes a consistent set of bids selected by the SO model in five of the nine price-policy scenarios. The second bid portfolio, which includes the same bids that are in the first bid portfolio plus an additional bid, was selected by the SO model in the other four price-policy scenarios. In the scenario-risk phase of the bid-selection process, the first bid portfolio was analyzed in the four price-policy scenarios where it was not selected as the least-cost bid portfolio. Similarly, the second bid portfolio was analyzed in the five price-policy scenarios where it was not selected as the least-cost bid portfolio.

As in the portfolio-development phase, these studies were performed using the SO model and PaR. The outputs from these studies were used to calculate the PVRR(d) between two system simulations--one that includes 2017R RFP bids and the Transmission Projects and one without. The company then used the PVRR(d) results to initially identify the least-cost, least-risk bid portfolio.

Q. Did the company identify any issues in the modeling initially used in the portfolio-development phase and scenario-risk phase of the bid-selection process?

A. Yes. On-going due-diligence review of the least-cost, least-risk bid portfolio allowed the company to identify two issues with specific bids that affected the initial economic analysis. First, the company discovered that capacity factor adjustments applied to two bids were only partially captured in the SO model and PaR simulations. Consistent with recommendations from Sapere Consulting, the net capacity factor for two projects were assessed at 92 percent of the net capacity factor proposed by [redacted]. When applying the net-capacity-factor adjustment in the SO model and PaR, its impact on federal PTC benefits and bid costs were accurately captured.

However, its impact on the expected energy output was not captured. This had the effect of overstating net power cost ("NPC") benefits associated with these bids, one of which was included in the initial least-cost, least-risk bid portfolio.

The second issue was identified when reviewing redline edits made by [redacted] to the 2017R RFP pro-forma BTA. Specifically, the company noticed that [redacted], which submitted several BTA bids, with two of these bids initially included in the least-cost, least-risk bid portfolio, struck language specifying that it would be responsible for applicable sales taxes. [redacted] subsequently confirmed that its price proposals did not include sales tax, and the company confirmed that it did not include sales tax in its evaluation of costs for any of the [redacted] BTA bids.

Q. How did the company evaluate the impact of these two issues in the bid-selection process?

A. The company first corrected the net-capacity-factor inputs for the two projects proposed by [redacted] and included the estimated cost of sales tax on all of the [redacted] BTA bids. Once these corrections were made, the company reran the SO model portfolio-development studies for two price-policy scenarios--one pairing low natural-gas prices with zero CO_2 prices and one pairing medium natural-gas prices with medium CO_2 prices.

Q. Did the correction to the net-capacity-factor inputs for the [redacted] bids cause a change in the bid portfolio in these updated SO model studies?

A. No. The [redacted] bid that was included in the original least-cost, least-risk bid portfolio continued to be selected by the SO model in both price-policy scenarios.

Q. Did the application of sales tax to the [redacted] BTA bids cause a change in the bid portfolio in these updated SO model studies?

A. Yes. When sales tax was added to the cost of the [redacted] BTA bids, one of its two projects that was originally included in the initial least-cost, least-risk bid portfolio was replaced with another bid. Specifically, [redacted] BTA bid for the [redacted] was replaced with [redacted] for the [redacted].

Q. Did the company update its economic analysis to account for this update to the bid portfolio?

A. Yes. The economic analysis among all nine price-policy scenarios was refreshed to reflect this updated bid portfolio, representing the 2017R RFP final shortlist, with corrected cost-and-performance inputs. This analysis was updated using the SO model and PaR. I describe the company's updated economic analysis for the Combined Projects including the 2017R RFP final shortlist later in my supplemental direct testimony.

Q. Did the company inform the Utah and Oregon IEs of changes to the 2017R RFP final shortlist resulting from the corrections applied to the modeling described above?

A. Yes. When issues related to the application of net-capacity factor adjustments and the omission of sales tax in the economic analysis were discovered, the company notified the Utah and Oregon IEs to explain the impact on the 2017R RFP final shortlist and the impact on the economic analysis.

Q. Did the Oregon IE request any additional sensitivity studies during its review of the 2017R RFP final shortlist analysis?

A. Yes. As I will address more fully later in my supplemental direct testimony, the company's bid-selection modeling, performed using the SO model and PaR, reflects nominal federal PTC inputs, to be consistent with how federal PTC benefits will flow into customer rates, where applicable, rather than levelized federal PTC inputs. To understand the impact of this assumption on bid selections, the Oregon IE requested that the company produce an SO model sensitivity, with levelized PTCs, using medium natural-gas price and medium CO_2 price assumptions to understand how treatment of federal PTCs affects bid selection. The Utah IE also expressed interest in seeing this sensitivity.

Q. What were the findings from this IE sensitivity?

A. When federal PTCs applicable to BTA bids and benchmark bids are levelized, the SO model replaces two BTA bids and a benchmark bid with two PPA bids. The PVRR(d) net benefits in the IE sensitivity, calculated from projected system costs through 2036 from the SO model, are lower in the IE sensitivity than they are in the economic analysis using the 2017R RFP final shortlist. In reviewing these results with the IEs, the company also highlighted that the bid portfolio in the IE sensitivity produces higher nominal costs when compared to the economic analysis based on the 2017R RFP final shortlist.

Q. Did the company change its 2017R RFP final shortlist based on the IE sensitivity?

A. No. While the IE sensitivity shows a change in the bid portfolio, this portfolio is selected based on federal PTC inputs that are inconsistent with how PTC benefits will be treated in customer rates. Moreover, the net benefits from the bid portfolio in the IE sensitivity produce lower PVRR(d) benefits and lower near-term nominal net-benefits than the bid portfolio reflected in the 2017R RFP final shortlist.

Q. Please describe the final shortlist of winning bids from the 2017R RFP.

A. The 2017R RFP final shortlist includes four new wind projects located in Wyoming from three different bidders. The total capacity of the four projects is 1,170 MW. The projects included in the final shortlist are summarized in Table 1-SD.

Table 1-SD. 2017R RFP Final Shortlist Projects

Project Name (Bidder)	Location	Capacity (MW)
TB Flats I & II (PacifiCorp)	Carbon & Albany Counties, WY	500
Cedar Springs (NextEra Energy Acquisitions)	Converse County, WY	400
McFadden Ridge II (PacifiCorp)	Carbon & Albany Counties, WY	109
Uinta (Invenergy Wind Development)	Uinta County, WY	161

Q. Are any of the winning bids the company's benchmark resources?

A. Yes. The TB Flats I and II and McFadden Ridge II projects are company-benchmark resources that will be developed under engineer, procure, and construction ("EPC") agreements. The Uinta project is being developed by Invenergy Wind Development under BTAs. The Cedar Springs project is being developed by NextEra Energy Acquisitions as a 50-percent BTA and a 50-percent PPA. In total, the final shortlist includes 361 MW that will be developed under BTAs, 609 MW of benchmark capacity that will be developed under EPC agreements, and 200 MW that will deliver energy and capacity under a PPA.

Q. Please summarize the cost-and-performance attributes of the winning bids.

A. The total in-service capital cost for the winning bids is $1.30 billion, down from the

$1.37 billion assumed in the company's initial filing. Considering that the winning bids represent an increase in total owned-wind capacity (from just over 860 MW in the company's initial filing to approximately 970 MW), the per-unit capital cost for final shortlist bids is down approximately 17 percent from $1,590/kW to $1,320/kW.

In addition to these capital costs, the PPA price that will be paid to NextEra Energy Acquisitions for 50 percent of the output from the Cedar Springs project is expected to add approximately [redacted] to total-system NPC [redacted]. These costs are significantly lower than proxy PPA costs that were based off of certain QF projects that were included in the company's initial filing, which were assumed to add [redacted] to total-system NPC beginning 2022, rising to [redacted] by the end of 2041. This proxy QF project, which requires interconnection facilities beyond the Aeolus-to-Bridger/Anticline transmission line that cannot be built until 2024, is no longer included in the company's economic analysis of the Combined Projects.

In aggregate, the winning bids are expected to operate at a capacity-weighted average annual capacity factor of 40.3 percent.

The in-service cost for network upgrades required to interconnect the final shortlist projects total [redacted], and the cost to build the Aeolus-to-Bridger/Anticline transmission line remains at [redacted]. The expected cost-and-performance attributes for the winning bids and the Transmission Project is summarized in more detail in Confidential Exhibit RMP__(RTL-1SD).

Q. How did the company verify the forecasted capacity factors in its review of bids during the 2017R RFP?

A. The company retained an independent third-party expert, Sapere Consulting, to evaluate the capacity factors proposed for each bid selected to the initial shortlist. Sapere Consulting's report is attached as Confidential Exhibit RMP__(RTL-2SD).

Q. Did the company adjust any of the performance data for bids included in the initial shortlist based on the report prepared by Sapere Consulting?

A. Yes. Consistent with recommendations from Sapere Consulting, the net capacity factor for the [redacted] bids were assessed at 92 percent of the net capacity factor proposed by [redacted]. No adjustments were applied to any of the other bids.

Q. As part of the 2017R RFP process, did the company perform any preliminary viability assessments for the projects included in the final shortlist?

A. Yes. The company reviewed each project's place in the transmission interconnection queue and how each project will qualify for federal PTCs. The company also reviewed bid materials to evaluate site control, progress in collecting avian data, and permitting timelines. All of the projects have either initiated or received system impact studies and are expected to be able to execute interconnection agreements that support the proposed commercial-operation dates. All of the projects will qualify for the full value of PTCs by having secured safe-harbor equipment and by meeting continuity-of-construction requirements, as described in Ms. Nikki L. Kobliha's testimony, by coming online by the end of 2020. All of the final shortlist projects have demonstrated they have site control, have reasonable permitting timelines that will allow the projects to be place in service by the end of 2020, and have initiated collection of avian data.

Q. What is the status of the 2017S RFP?

A. The company received initial bids for new solar resources on December 11, 2017. On January 8, 2018, PacifiCorp established an initial shortlist, considering both price and non-price scoring elements, which was subsequently submitted to the Solar RFP IE for review. As was the case with the 2017R RFP, the market response to the 2017S RFP was robust. The company received solar resource proposals from 31 bidders offering 109 bid alternatives for 46 solar projects. In aggregate, 6,496 MW of new solar resource capacity was bid into the 2017S RFP. After completing its bid-eligibility screening, a process that ensures all bids satisfy minimum-bid requirements that are specified in the 2017S RFP, the company disqualified 32 bid alternatives, which equates to 3,039 MW of new solar resource capacity.

Q. Did the company review those bid alternatives that did not meet minimum-bid requirements with the Solar RFP IE?

A. Yes. The Solar RFP IE reviewed the company's minimum-eligibility criteria and determined that these criteria are consistent with other renewable resource RFPs. The Solar RFP IE also reviewed the specific bid alternatives that were disqualified, and in all instances, found that the disqualified bids clearly did not meet the minimum-eligibility criteria listed in the RFP.

Q. Has the Solar RFP IE commented on any other elements of the on-going RFP process?

A. Yes. On January 10, 2018, the Solar RFP IE submitted its first status report, where it concluded that the 2017S RFP documents are clear and the 2017S RFP has been conducted in a clear and transparent manner.

Q. Please summarize the bids selected to the initial shortlist from the 2017S RFP.

A. The 2017S RFP initial shortlist includes PPAs bids from 10 projects proposed by seven bidders totaling 1,629 MW. The majority of the projects (1,414 MW) are located in Utah, and the remaining initial shortlist bids are located in Oregon (114 MW) and Washington (100 MW). All of the bids on the 2017S RFP initial shortlist have proposed PPAs with commercial-operation dates ranging between November 2020 and January 2021--approximately one year before the initial ramp down in investment-tax credits.

Q. Has the company determined whether it will pursue any bids from the 2017S RFP?

A. No. The company continues to evaluate potential bids in the 2017S RFP and has not yet established a final shortlist. There are several outstanding milestones that have to be met before establishing a final shortlist. Under the 2017S RFP schedule, the Solar RFP IE will complete its review of the initial shortlist no later than January 29, 2018, and then bidders will be asked to submit best-and-final pricing no later than February 5, 2018. Once best-and-final pricing is received, the company plans to identify a final shortlist by mid-March 2018.

Q. Has the company analyzed how the potential selection of bids from the 2017S RFP might affect the economic analysis of the 2017R RFP final shortlist?

A. Yes. Using cost-and-performance data from the bids submitted into the 2017S RFP, the company analyzed how the potential selection of these bids would impact the economic analysis of the winning bids from the 2017R RFP. I describe this sensitivity analysis later in my supplemental direct testimony.

UPDATED ECONOMIC ANALYSIS

Q. What assumptions did the company update before refreshing its economic analysis of the Combined Projects?

A. The models were updated to reflect: (1) cost-and-performance assumptions for the Wind Projects consistent with the winning bids selected to the 2017R RFP final shortlist as summarized earlier in my supplemental direct testimony; (2) current load-forecast projections; (3) current price-policy scenario assumptions; and (4) recent changes in federal tax rate for corporations.

Q. Please describe the updated cost-and-performance estimates for the Wind Projects.

A. The updated economic analysis includes the capital costs associated with the winning bids, the costs associated with the Cedar Springs PPA, and the updated net capacity factors, as described above. The updated economic analysis also captures terminal-value benefits from BTA and EPC-benchmark bids, where the company retains control of the site at the end of the asset life. These benefits were considered in the 2017R RFP bid-selection process, consistent with the bid-evaluation methodology described in the RFP, and therefore, they are applied in the updated economic analysis.

Q. What is captured by the terminal value applied to BTA and EPC-benchmark bids?

A. When a wind asset reaches the end of its life (assumed to be 30 years), equipment associated with the wind asset itself has been fully depreciated. However, transmission assets required to interconnect the wind facility have a longer life (assumed to be 62 years). At the time the wind asset reaches the end of its life, the transmission assets required for interconnection have approximately 32 years of additional life remaining.

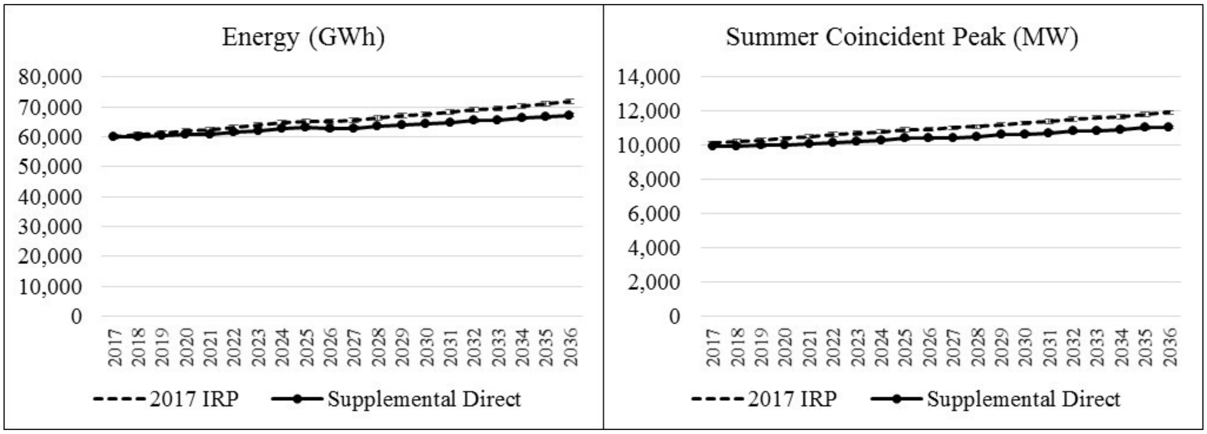
With an owned-wind facility where the company retains control of the site, whether developed as a BTA or an EPC-benchmark, that site can be redeveloped using existing transmission assets that have not been fully depreciated. Consequently, relative to the future development of a new greenfield wind project, the redevelopment of an existing site limits incremental transmission interconnection costs. Similarly, with an owned facility, an existing site can be redeveloped with limited incremental project-development costs, thereby reducing the cost to acquire development rights relative to a new site. These terminal-value benefits are not applicable to a PPA bid, where a third-party retains control of the site.

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 IRP. This 2017 IRP load forecast was finalized in December 2016. The updated economic analysis uses the company's new load forecast completed in the summer of 2017, after the company made its initial filing.

Figure 1-SD 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-SD. Comparison of the 2017 IRP and Updated Load Forecast Assumptions



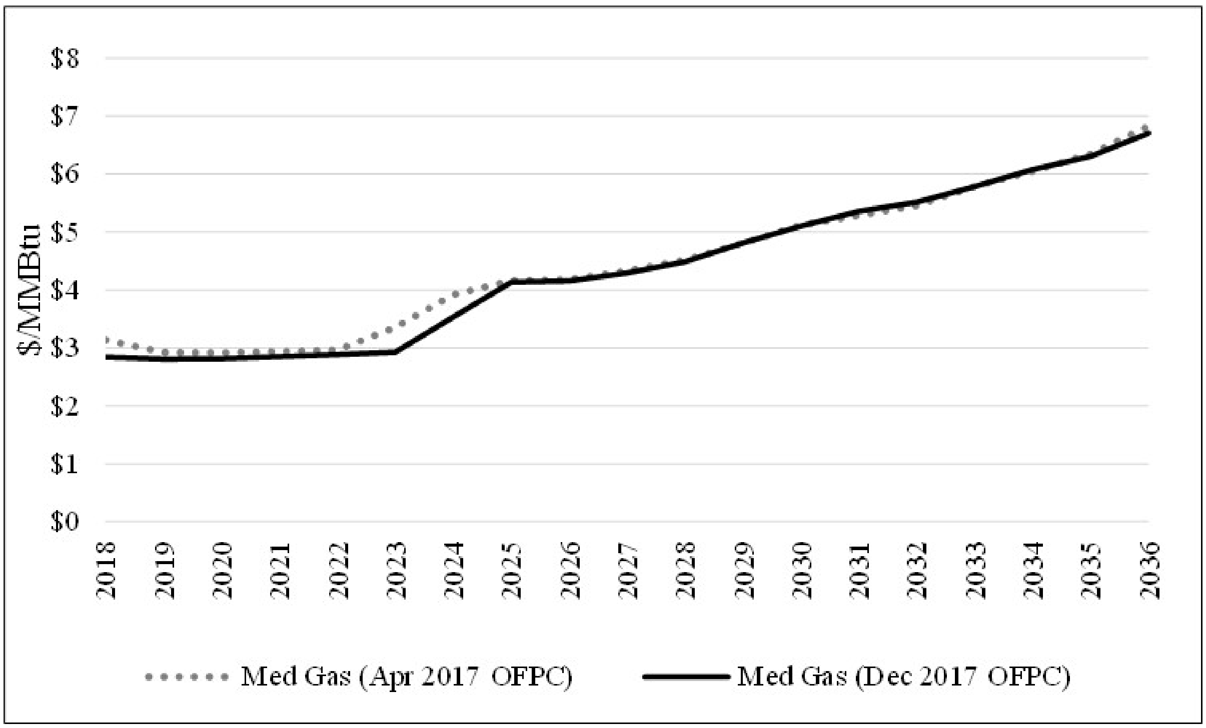
Changes in the load forecast are primarily driven by: (1) a reduction in Utah and Wyoming industrial loads principally due to reduced usage projections for a number of large customers; (2) increases in the growth of customer generation from 2017 to 2018, contributing to reductions in Utah residential 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-policy assumptions 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). The medium natural-gas price assumptions were derived from the company's OFPC. In the economic analysis summarized in my direct testimony, the company used its April 26, 2017 OFPC.

The company's most recent OFPC is dated December 30, 2017, which reflects more current market forwards and an updated forecast from [redacted]. Figure 2-SD 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 December 30, 2017 OFPC. Over the period 2018 through 2036 and using the most current discount rate, the nominal levelized price for Henry Hub natural-gas prices has decreased by approximately three percent from $4.06/MMBtu to $3.94/MMBtu.

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



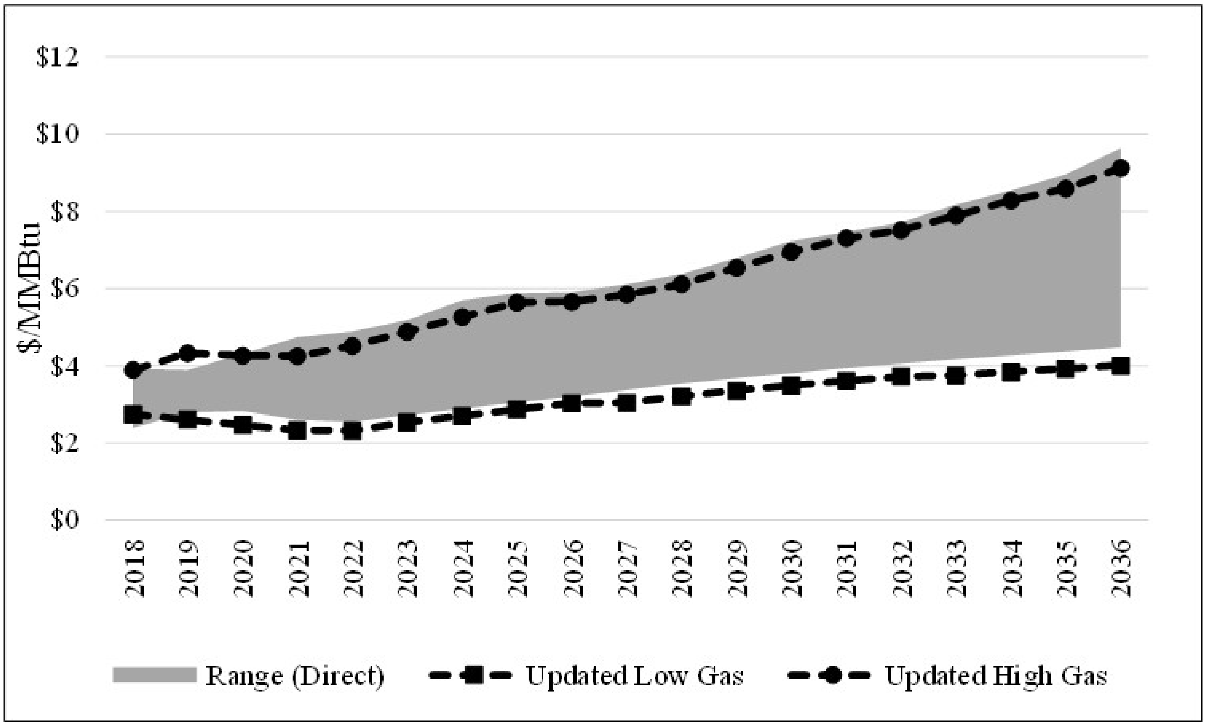
The updated OFPC reflects market forwards as of December 30, 2017 over the period January 2018 through January 2024. The decrease in levelized prices between the updated OFPC and the April OFPC used in the company's original economic analysis is primarily driven by a reduction in market forwards. Prices in the updated market fundamentals forecast from [redacted], which are used exclusively in the OFPC beyond January 2025, track closely with those assumed in the April 2017 OFPC. The company continues to blend market forwards from month 61 (February 2023) through month 72 (January 2024) with the fundamentals-based forecast from month 85 (February 2025) through month 96 (January 2026) to establish prices in month 73 (February 2024) through month 84 (January 2025).

Q. Did the company update the low and high natural-gas price scenarios used in the updated economic analysis?

A. Yes. Consistent with the company's approach to develop low and high natural-gas price scenarios used in the original economic analysis, low and high natural-gas price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted], [redacted], and the U.S. Department of Energy's Energy Information Administration. Exhibit RMP__(RTL-3SD) shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios in the company's updated economic analysis of the Combined Projects.

Figure 3-SD shows the range between the low and high natural-gas price scenarios used in the company's original economic analysis alongside the updated low and high natural-gas price assumptions. Nominal levelized prices in the low and high scenarios are $2.95/MMBtu (down by approximately seven percent) and $5.60/MMBtu (down by approximately four percent), respectively.

Figure 3-SD. Updated Low and High Natural-Gas Price Assumptions



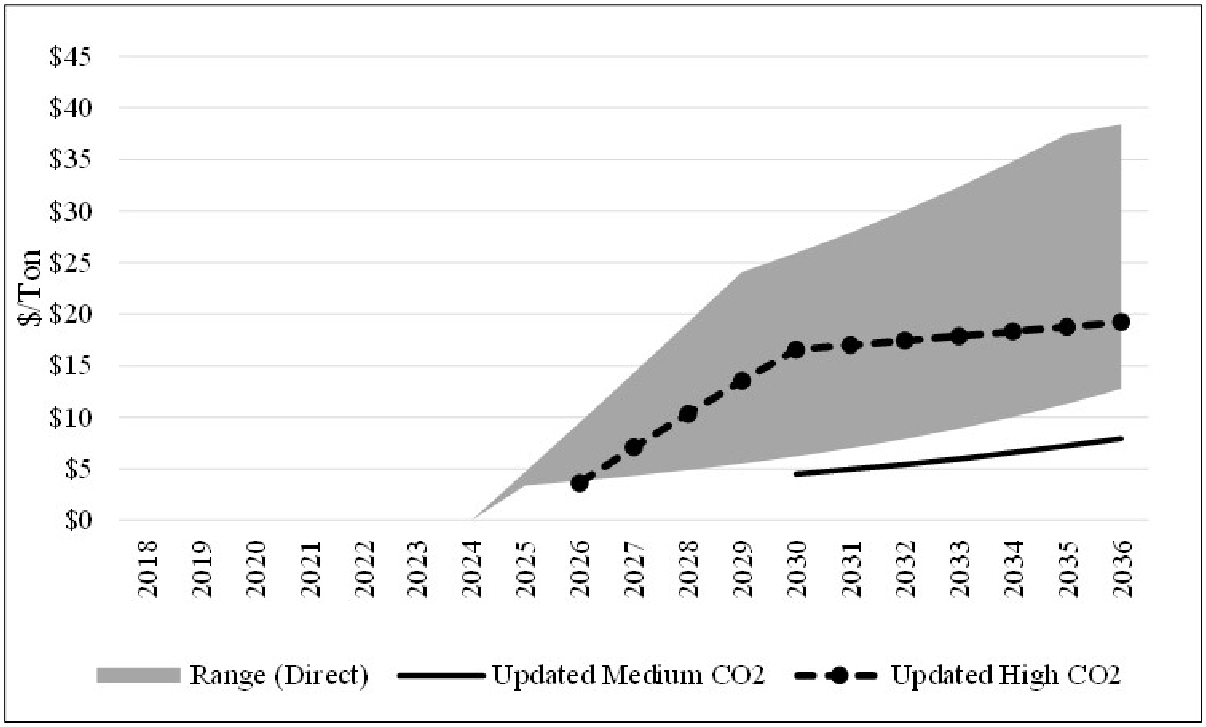
Q. Did the company update its CO_2 price scenarios used in its updated economic analysis?

A. Yes. As with natural-gas price assumptions and consistent with the company's approach to develop low and high CO_2 price scenarios used in the original economic analysis, low and high CO_2 price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted] and [redacted]. To bracket the low end of potential-policy outcomes, the company continues to assume there are no future policies adopted that would require incremental costs to achieve emission reductions in the electric sector. For this scenario, the assumed CO_2 price is zero.

Figure 4-SD shows the range between the medium and high CO_2 price scenarios used in the company's original economic analysis alongside the updated medium and high CO_2 price assumptions. The updated medium and high CO_2 price assumptions are lower and start later relative to the assumptions summarized in my direct testimony.

Updated CO_2 prices in the medium scenario begin in 2030 (five years later) at $4.49/ton and rise to $7.95/ton by 2036. Updated prices in the high scenario begin in 2026 (one year later) at $3.62/ton, rise to $16.55/ton by 2030, and reach $19.23/ton by 2036.

Figure 4-SD. Updated Medium and High CO_2 Price Assumptions



Q. Please describe the updated federal tax rate for corporations that was included in the updated economic analysis of the Combined Projects.

A. The company's updated analysis assumes a 21-percent federal income tax rate. Based on an assumed net state income tax rate of 4.54 percent, the effective combined federal and state income tax rate used in the updated analysis is 24.587 percent.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and PaR in the updated economic analysis.

A. The effective combined federal and state income tax rate affects the company's post-tax weighted-average cost of capital ("post-tax WACC"), which is used as the discount rate in the SO model and PaR. With the changes in tax law, the company's discount rate has been updated from 6.57 percent to 6.91 percent.

The modified income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model, including the selection of bids from the 2017R RFP. 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. 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 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 the company's system.

Finally, the updated income tax rate 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. The updated combined federal and state income tax rate reduces the revenue requirement associated with federal PTCs from $38.68/MWh to $31.82/MWh, adjusted for inflation over time. The impact of the updated income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

Q. How were these assumption updates captured in the updated economic analysis of the Combined Projects?

A. The company updated the SO model and PaR to reflect these updated assumptions. As was done in the original analysis summarized in my direct testimony, these models were used to calculate the PVRR(d) between a simulation with and without the Combined Projects after applying the modeling updates. These simulations continue to cover a forecast horizon out through 2036. The company also updated its calculation of the PVRR(d) from the change in nominal revenue requirement due to the Combined Projects through 2050.

Q. In addition to the assumption updates described above, did the company change how it applied federal PTC benefits in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. When establishing the 2017R RFP final shortlist, the company applied PTC benefits for applicable bids (BTAs and benchmark-EPC bids) on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for these bids will flow through to customers and aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050. It also ensures the 2017R RFP bid selections from the SO model more accurately reflect the difference in how BTA and benchmark-EPC bids are expected to impact customer rates.

Q. Did the company continue to apply revenue requirement associated with capital costs on a levelized basis in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. When setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because revenue requirement from capital projects is spread over the life of the asset in rates, these costs continue to be treated as a levelized cost in the SO model and PaR simulations. As was done in the company's original economic analysis to estimate the nominal revenue requirement impacts from the Combined Projects, revenue requirement from capital associated with the Combined Projects is treated as a nominal cost when the results are extrapolated out through 2050.

UPDATED SYSTEM-MODELING PRICE-POLICY RESULTS

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

A. Table 2-SD summarizes the updated PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects, reflecting winning bids from the 2017R RFP, 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-4SD).

Table 2-SD Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO2	($145)	($104)	($109)
Low Gas, Medium CO2	($186)	($124)	($131)
Low Gas, High CO2	($297)	($258)	($272)
Medium Gas, Zero CO2	($306)	($246)	($258)
Medium Gas, Medium CO2	($343)	($311)	($327)
Medium Gas, High CO2	($430)	($388)	($406)
High Gas, Zero CO2	($619)	($509)	($535)
High Gas, Medium CO2	($636)	($539)	($567)
High Gas, High CO2	($696)	($605)	($636)

Over a 20-year period, the Combined Projects reduce 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) net benefits range between $311 million, when derived from PaR stochastic-mean results, and $343 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 net benefits increase with higher natural-gas price assumptions, and similarly, increase with higher CO_2 price assumptions. Conversely, system net benefits 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. Importantly, both models continue to show that the net benefits from the Combined Projects 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 2-SD do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the updated performance estimates discussed above, customer benefits for all price-policy scenarios would improve by approximately $31 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2036 (up from $26 million in my original analysis). Quantifying the potential upside associated with incremental REC revenues is simply intended to communicate that the net benefits from the Combined Projects could improve if the incremental RECs can be monetized in the market.

Q. Is there additional upside to the net benefits shown in Table 2-SD?

A. Yes. Before receiving bids submitted into the 2017R RFP, the company locked down with the IEs default operations and maintenance ("O&M") assumptions that were applied to BTA and benchmark-EPC bids beyond proposed O&M agreement periods. These assumptions were based on the company's experience in operating and maintaining the existing fleet of owned-wind facilities, and were used in the bid-selection process and the economic analysis summarized above.

Since construction of the company's existing fleet of wind facilities, wind technology has evolved and turbine sizes have increased. With the increase in turbine size, O&M costs are expected to be lower than actual experience because there are fewer turbines on a given site. The range in cost savings is expected to vary between 31 to 42 percent of certain O&M cost elements (*i.e.*, materials and O&M contract costs). Two of the winning bids--Invenergy Wind Development's Uinta project and the company's TB Flats I and II project--will use larger-turbine equipment for a portion of the wind turbines on each site. If the O&M cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18-percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $13 million.

UPDATED REVENUE-REQUIREMENT MODELING PRICE-POLICY RESULTS

Q. Did the company 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, the company updated its forecast of the change in nominal annual revenue requirement due to the Combined Projects, incorporating the modeling updates described earlier my testimony.

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

A. Table 3-SD 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-5SD).

Table 3-SD. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO2	$169
Low Gas, Medium CO2	$133
Low Gas, High CO2	($105)
Medium Gas, Zero CO2	($60)
Medium Gas, Medium CO2	($177)
Medium Gas, High CO2	($301)
High Gas, Zero CO2	($437)
High Gas, Medium CO2	($479)
High Gas, High CO2	($585)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned wind projects included in the 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer benefits range from $60 million in the medium natural-gas, zero CO_2 scenario, to $585 million in the high natural-gas, high CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the Combined Projects are $177 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results show that upside benefits far outweigh downside risks.

Q. Is there additional 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 3-SD do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the updated performance, customer benefits for all price-policy scenarios would improve by approximately $39 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2050 (up from $34 million in my original analysis).

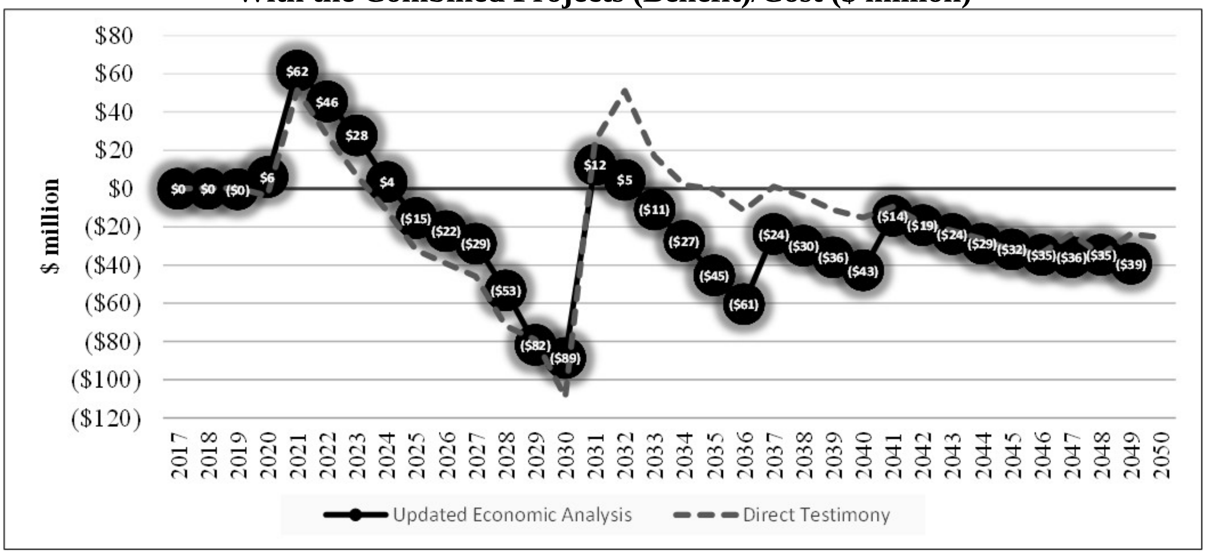
Q. Is there additional potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. As discussed above, the company anticipates O&M costs for those projects that will install larger turbine equipment to be lower than what has been reflected in the updated economic analysis. Accounting for these cost savings, customer benefits for all price-policy scenarios would improve by approximately $22 million when calculated from projected operating costs through 2050.

Q. Please describe the change in annual nominal revenue requirement from the Combined Projects.

A. Figure 5-SD shows the updated change in nominal revenue requirement due to the Combined Projects for the medium natural-gas, medium CO_2 price-policy scenario on a total-system basis. These results are shown alongside the same results from the original economic analysis summarized in my direct testimony. The change in nominal revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 5-SD Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct testimony. This profile shows that despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits, reduce the magnitude and shorten the duration over which costs increase after federal PTCs for new wind resources expire, and continue to contribute to customer benefits over the long term.

The year-on-year reduction in net benefits from 2036 to 2037 is driven by the company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028-through-2036 time frame. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2033-to-2036 time frame, This extrapolation methodology is conservative because it results in project benefits not matching the levels observed in the model results for 2036 until 2044.

SOLAR SENSITIVITY

Q. Please describe the sensitivity studies that analyzed the impact of the solar bids received in the 2017S RFP on the economics of the Combined Projects.

A. The company's solar sensitivity analysis used the SO model and PaR simulations to determine the PVRR(d) based on two model runs--one with solar PPA bids and the Combined Projects and one with solar PPA bids but without the Combined Projects. In the sensitivity where PPA bids are pursued with the Combined Projects, the SO model continues to choose the winning bids included in the 2017R RFP final shortlist as part of the least-cost bid portfolio. Depending upon the price-policy scenario, between 1,118 MW and 1,315 MW of solar PPA bids, from new projects all located in Utah, are added to the system by the SO model.

Q. What were the results of the solar sensitivity where solar PPA bids are assumed to be pursued in lieu of the Combined Projects?

A. Table 4-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 4-SD Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	($334)	($343)	$9
PaR Stochastic Mean	($203)	($311)	$108
PaR Risk Adjusted	($213)	($327)	$114
Low Gas, Zero CO2			
SO Model	($206)	($145)	($61)
PaR Stochastic Mean	($126)	($104)	($22)
PaR Risk Adjusted	($133)	($109)	($24)

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $114 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with solar PPA bids and without the Combined Projects has higher net customer benefits relative to a portfolio containing just the Combined Projects. The increase in net benefits in the solar PPA portfolio is $24 million based on the risk-adjusted PaR results.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SD Solar Sensitivity with Solar PPAs Included
With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	**Benchmark PVRR(d)**	**Change in PVRR(d)**
Medium Gas, Medium CO2			
SO Model	($602)	($343)	($259)
PaR Stochastic Mean	($442)	($311)	($131)
PaR Risk Adjusted	($464)	($327)	($137)
Low Gas, Zero CO2			
SO Model	($286)	($145)	($141)
PaR Stochastic Mean	($185)	($104)	($81)
PaR Risk Adjusted	($195)	($109)	($86)

When the solar PPAs are pursued in addition to the Combined Projects, the total benefits increase, but are diluted (*i.e.*, the aggregate net benefits are less than the sum of the benefits for the cases where Combined Projects or solar PPAs are pursued independently).

Q. What conclusions can you draw from these solar sensitivity analyses?

A. These sensitivities demonstrate that should the company choose to pursue solar bids through the 2017S RFP, the resulting solar PPAs would not displace the Combined Projects as an alternative means to deliver economic savings for customers.

While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces a PVRR(d) with net benefits that are slightly higher than a portfolio without the solar PPAs in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. This sensitivity does not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table. Importantly, the sensitivity that evaluates the Combined Projects with the solar PPAs produces net benefits that are greater than the net benefits from the Combined Projects without the solar PPAs. This confirms that near-term renewable procurement is not a matter of whether the company should pursue the Combined Projects *or* the solar PPAs, but whether the company should consider both opportunities. At this time, it is clear that the Combined Projects provide significant net benefits, and that these benefits are not eliminated if the company were to also pursue solar PPA bids through the 2017S RFP.

WIND-REPOWERING SENSITIVITY

Q. Has the company updated its sensitivity analysis related to the wind repowering project?

A. Yes. Based on the updates discussed above, coupled with the updated cost-and performance estimates for the wind repowering project (described in Docket No. 17-035-39), the company performed a sensitivity that includes the repowered wind facilities assuming they continue to operate within the limits of their large generator interconnection agreements ("LGIAs").

Q. What were the results of the wind-repowering sensitivity?

A. Table 6-SD summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 6-SD Wind-Repowering
Sensitivity (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	**Benchmark PVRR(d)**	**Change in PVRR(d)**
Medium Gas, Medium CO2			
SO Model	($541)	($343)	($198)
PaR Stochastic Mean	($475)	($311)	($164)
PaR Risk Adjusted	($498)	($327)	($171)
Low Gas, Zero CO2			
SO Model	($313)	($145)	($169)
PaR Stochastic Mean	($255)	($104)	($152)
PaR Risk Adjusted	($268)	($109)	($159)

In the wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural-gas, medium CO_2, and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but also increase, if both the wind-repowering project and the Combined Projects are completed.

REBUTTAL TESTIMONYRESOURCE NEED

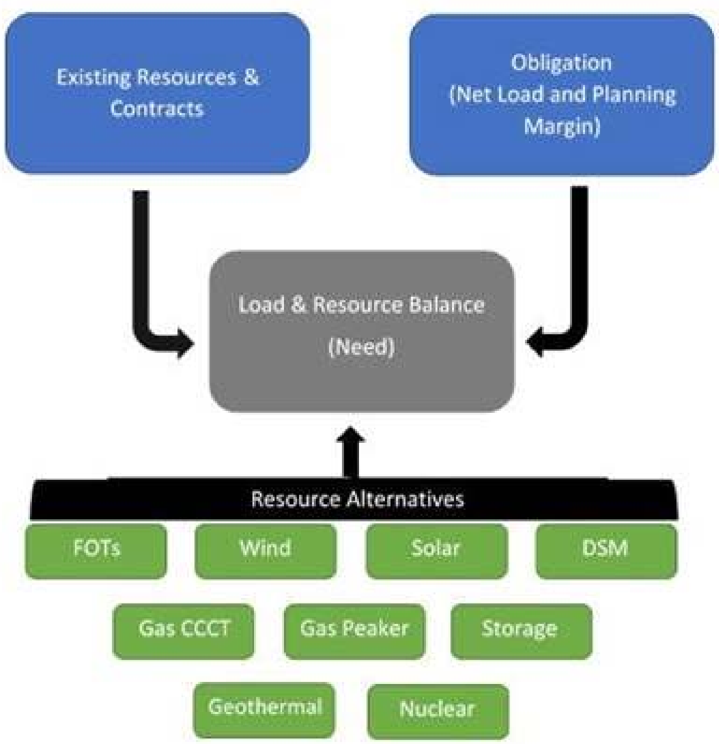
Q. Dr. Zenger, Mr. Vastag, and Mr. Mullins argue that the Combined Projects are not tied to a specific resource need. (Zenger Direct, pages 9-11; Vastag Direct lines 53-64; Mullins Direct, page 10, lines 17-20.) Do you agree?

A. No. The Combined Projects meet both near-term and long-term resource needs identified in the company's 2017 IRP. The Combined Projects leverage federal PTCs to provide least-cost resources that meet these needs, and do so with substantial savings to customers.

Q. How does the company develop its forecast of resource need?

A. Resource need is the product of a load-and-resource balance, which is reported in the IRP. Figure 1-R summarizes the elements of the load-and-resource balance that are used to establish resource need, and once identified, how that need can be met.

Figure 1-R. Elements of the Load-and-Resource Balance



There are two basic elements to the load-and-resource balance: (1) existing resources and committed contracts; and (2) obligations. Existing resources and committed contracts account for any planned or assumed resource retirements and contract terminations over time. Obligations include load, net of customer-sited generation and interruptible contracts, over time. Obligations also include a planning margin, which represents an incremental planning requirement, applied as an increase to the projected obligation, to ensure sufficient capacity on the system to manage uncertain events (*i.e.*, weather and outages) and known requirements (*i.e.*, operating reserves). In recent IRPs, including the 2017 IRP, the company assumes a 13-percent planning margin.

The load-and-resource balance reflects the difference between these two basic elements. When existing resources and contracts exceed obligations, the company has sufficient resources to reliably meet customer needs. When existing resources and contracts are less than its obligations, the company has a resource need. This balance between existing resources, including committed contracts, and obligations can change over time. When the company faces a resource need, the IRP is used to evaluate a wide range of supply-side resources (*i.e.*, renewable resources, gas-fired resources, uncommitted front-office transactions or "FOTs", *etc*.) and demand-side resources (*i.e.*, demand-side management resources or "DSM") that can be used to meet that need over time. Different types of resource portfolios that can be used to meet a resource need are evaluated in the IRP to determine which portfolio is least cost, accounting for risk.

Q. Does the load-and-resource balance presented in the 2017 IRP show a near-term resource need?

A. Yes. Accounting for assumed resource retirements, contract terminations, and incremental DSM savings from the preferred portfolio, the 2017 IRP shows a near-term resource need of 527 MW in 2017 rising to 1,023 MW in 2021, the first full year the Combined Projects will be placed in service.[1] The resource need grows over time with load growth, existing resource retirements, and committed contracts terminations.

Q. Do the Combined Projects fully satisfy the near-term resource need identified in the 2017 IRP load-and-resource balance?

A. No. In the 2017 IRP, the company updated its capacity contribution values for wind and solar resources. Based on these values, 15.8 percent of Wyoming wind resource capacity can be relied upon at times when the system is most likely to experience conditions where load exceeds available resources. Consequently, the 1,100 MW of new Wyoming wind in the 2017 IRP preferred portfolio meets approximately 174 MW (17 percent) of the 1,023 MW resource need in 2021. The remaining resource need in 2021 (83 percent) is met with uncommitted FOTs.

Q. If the Combined Projects were not included in the resource portfolio, how would the 2021 resource need be met?

A. Resource portfolios that do not include the Combined Projects include more uncommitted FOTs. The resource portfolios with more uncommitted FOTs are higher cost than resource portfolios that include the Combined Projects under a wide range of price-policy scenarios. Simply stated, resource portfolios with the Combined Projects

[1] Table 5.15, PacifiCorp's 2017 IRP, Volume I.

displace FOTs in the near-term because the Combined Projects, accounting for PTC savings, are lower cost and lower risk than FOT resource alternatives.

Q. Has the company previously acquired renewable resources that displace FOTs?

A. Yes. This is not the first time the company has implemented a least-cost, least-risk plan to procure renewable resources that displace uncommitted FOTs. In fact, all 1,698 MW of PacifiCorp's existing contracted and owned renewable resources included in rates today, not including QFs, were acquired and approved by the Commission because they were the least-cost, least-risk resources, displaced FOTs, and were acquired well before any thermal capacity or state renewable portfolio standard need.

Q. Mr. Mullins claims that FOTs do not represent fulfillment of a resource need. (Mullins Direct, page 15, lines 1-4.) Is this true?

A. No. Mr. Mullins claims that the 2017 IRP shows currently available resources and FOTs will meet the company's resource needs through 2026 and therefore the Combined Projects "cannot be reasonably characterized as addressing a resource need." (Mullins Direct, page 12, lines 10-11.) This claim improperly assumes that the maximum level of FOTs assumed in the IRP are committed resources and that other resource alternatives, such as the Combined Projects, cannot be used to meet the projected resource need at a lower cost. As noted above, in the IRP, FOTs represent *uncommitted* resources, meaning they can be displaced if lower-cost alternatives are available. As the 2017 IRP shows, the energy and capacity provided by the Wind Projects are lower cost than other resource alternatives, including FOTs.

Q. Is Mr. Mullins' testimony here inconsistent with prior positions taken by UAE?

A. Yes. I understand that in Docket No. 15-035-53, UAE (as part of the Rocky Mountain

Coalition for Renewable Energy ("Coalition")), argued that it was "incorrect . . . that the [company's 2015] IRP shows no need for additional resources for over a decade, and that QF PPAs thus represent unneeded resources." *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Docket No. 15-035-53, Post Hearing Brief of the Rocky Mountain Coalition for Renewable Energy at 9-10 (Dec. 9, 2015). UAE argued: "To the contrary, the IRP demonstrates a need for significant new resources, which PacifiCorp primarily proposes to secure through short-term FOTs." *Id. See also In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Docket No. 15-035-53, Tr. pg. 234, lines 11-20 (Nov. 12, 2015) (Coalition witness Kevin C. Higgins testified that the "IRP calls for the purchase of around one million megawatt hours per year in front-office transactions from 2016 to 2024" and that these transactions could be displaced by lower cost alternatives). Mr. Mullins' position here, on behalf of UAE, is contradicted by UAE's prior advocacy.

Q. Has any other party recognized that FOTs are used to meet near-term resource needs?

A. Yes. I understand that in the company's 2015 IRP docket, DPU noted: "Near-term resource needs continue to be met with DSM and FOTs." *PacifiCorp's 2015 Integrated Resource Plan*, Docket No. 15-035-04, Division Comments on PacifiCorp's 2015 IRP at 24 (Aug. 25, 2015). Thus, DPU's position in this case is also contradicted by its prior comments.

Q. What factors influence the type of resources used to meet the company's resource need over the long term?

A. Uncommitted FOTs are traditionally one of the lowest-cost resources that can be used to meet a resource need. This is because the cost of these FOT resources reflect only the marginal, variable operating cost of existing resources selling excess firm energy to market participants on a forward basis. While the availability of PTCs changes this dynamic for the Combined Projects, supporting their inclusion in the company's resource portfolio by the end of 2020, uncommitted FOTs are still generally lower cost than *other* resource alternatives. Consequently, as the resource need grows over time, the level of uncommitted FOTs in the preferred portfolio generally grows, approaching maximum limits.[2] The timing in which the resource need exceeds maximum uncommitted FOT limits, after accounting for other lower-cost alternatives such as the Combined Projects, is a strong indicator of when the company will require incremental generating resources to meet its long-term resource need.

Q. How do the new wind resources included in the company's 2017 IRP preferred portfolio meet a long-term resource need?

A. The company's 2017 IRP forecasts that maximum levels of uncommitted FOTs begin to exceed resource needs by just under 400 MW beginning in 2028. The 1,100 MW of Wyoming wind resources included in the 2017 IRP preferred portfolio in 2021 contributes 174 MW of system capacity. Consequently, the 2017 IRP analysis shows that these new wind projects will meet approximately 44 percent of the resource need

[2] These maximum limits are based on the company's active participation in the wholesale power markets, physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply.

incremental to the resource need that can be met with FOTs. Therefore, beginning in 2028, the new wind resources included in the 2017 IRP preferred portfolio in 2021 begin deferring the need for other, high-cost resource alternatives. In this sense, these new wind resources can be viewed as displacing higher-cost uncommitted FOT resources in the near-term and deferring other higher-cost resource alternatives over the long-term.

Q. While these new wind resources will be used to meet both near-term and long-term resource needs, are you aware of examples where the Commission deemed early acquisition prudent?

A. Yes. I understand that in 1974, the Commission found that the company's decision to overbuild capacity at its Huntington plan was prudent because "substantial long-range benefits will accrue to the Utah ratepayers by having the additional facilities at the lower cost . . . and that Utah Power made a wise decision in constructing the larger generation unit when it had the opportunity to do so." *Re Utah Power & Light Co.*, 6 P.U.R.4th 263 (1974) (finding it prudent to increase capacity from 300 MW to 400 MW and sell near-term excess capacity until needed to serve customers).

Q. Dr. Zenger, Mr. Vastag, and Mr. Hayet claim that the Combined Projects are an economic opportunity to capture PTCs and not tied to resource need. (Zenger Direct, lines 236-239; Vastag Direct, lines 1-2, 55-64; Hayet Direct, lines 148-149.) Is this a fair characterization of the Combined Projects?

A. No. The company's analysis shows that acquiring the new wind resources now, when they are PTC-eligible, will displace higher-cost resources in both the near and long terms. The PTCs affect the timing and economics of the new resource, not the need for the resource. The fact that the Combined Projects are a time-limited opportunity based on PTCs does not inherently indicate that they are disconnected from a resource need.

Q. Mr. Mullins claims that the Combined Projects could be viewed as a hedge against market prices, but that this benefit should be ignored. (Mullins Direct, page 16, lines 11-20.) How do you respond?

A. First, the company agrees that wind resources provide a valuable hedge against future price volatility and the risk of future carbon regulation because wind resources have no fuel costs or carbon emissions, facts I understand that the Commission has previously recognized. *See In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts*, Docket No. 12-035-100, Order on Motion to Stay Agency Action at 17 (Dec. 20, 2012) ("wind resources provide ratepayers a hedge against fuel price and environmental risks"). The company's assessment of the Combined Projects appropriately accounted for the valuable risk mitigation provided by wind resources.

Second, contrary to Mr. Mullins' characterization, the Combined Projects are not being acquired "solely for hedging value." (Mullins Direct, page 16, lines 19-20.) As discussed above, the Combined Projects meet an identified resource need and are lower cost and lower risk than other resource alternatives, including FOTs. The fact the Combined Projects provide hedging value and further reduce the company's generation portfolio risk is an attribute of the projects, not a fault.

Q. Mr. Mullins indicates that he was surprised when the company announced as part of its 2017 IRP process that its preferred portfolio included the Combined Projects. (Mullins Direct, page 6, lines 14-19.) Dr. Zenger claims that the Commission should be skeptical of the Combined Projects because they were introduced late in the planning process. (Zenger Direct, lines 247-255.) How do you respond?

A. The Combined Projects were a logical development as the 2017 IRP analysis evolved. In late 2016 and early 2017, the company continued to study and refine its resource portfolios, all of which contained new Wyoming wind resources. In reviewing these resource portfolios, it became clear that the amount of Wyoming wind included in these resource portfolios was limited by transmission constraints. The presence of the Wyoming wind resources in these initial portfolios led the company to assess whether additional wind resources enabled by advancing sub-segments of Energy Gateway West would further lower system costs. Consequently, after the January 2017 public input meeting, the company incorporated the Aeolus-to-Bridger/Anticline line as a specific sensitivity case in its broader Energy Gateway sensitivity analysis. In late February, the company's modeling of four Energy Gateway transmission sensitivities indicated there were potential benefits to including the Aeolus-to-Bridger/Anticline line in the portfolio. At the March 2017 public input meeting, the company presented this preliminary analysis to stakeholders, along with next steps that communicated the company's intention to further refine key assumptions for this sensitivity case.

While the pre-filing stakeholder review process of the Combined Projects was necessarily limited by the timing of the company's analysis and 2017 IRP filing deadlines, it was in customers' interest to consider these resources and ultimately include them in the 2017 IRP preferred portfolio. The company explicitly chose to share the results of its analysis with stakeholders as it was being produced. Given the time-sensitive nature of these resource opportunities, delaying the IRP to allow additional pre-filing review was not a viable option. Instead, the company expeditiously completed the necessary analysis and shared it with IRP stakeholders in real time.

Q. Were there wind resources in other scenarios?

A. Yes. The 2017 IRP analyzed all alternatives when identifying ways to meet customers' near-term and long-term resource needs, including incremental DSM savings, procurement of uncommitted FOTs, new supply-side resources, including new renewable resources, and changes in use of or upgrades to existing resources to develop the preferred least-cost, least-risk portfolio of resources. The company's 2017 IRP shows a need for new resources that can be partially met with new wind generation by the end of 2020 across almost all modeled portfolios. The company examined alternatives for meeting this near-term need, but transmission constraints limited wind resource options.

Q. Mr. Hayet argues that the preferred portfolio that included the Combined Projects was not "significantly better" than other modeled portfolios. (Hayet Direct, lines 138-40.) How do you respond?

A. It is not clear which of the many portfolios that the company developed and analyzed in the 2017 IRP that Mr. Hayet believes might be lower cost and lower risk than the preferred portfolio. Similarly, Mr. Hayet does not identify what criteria he is using to determine why some other resource portfolio should have been selected as the preferred portfolio. The company's selection of the preferred portfolio is supported by robust analysis and a thorough screening process that considers expected costs, risk, reliability, emissions, fuel diversity, and customer rate impacts. Throughout the portfolio-development-and-screening process, top-performing resource portfolios consistently included new PTC-eligible wind facilities. Resource portfolios that included the Aeolus-to-Bridger transmission line, which enables additional PTC-eligible wind resources, produced a risk-adjusted PVRR that was notably lower than portfolios that excluded these investments.

Q. Mr. Peaco claims that "the only alternative to the Combined Projects is not to pursue them" because there is no need for additional resources. (Peaco Direct, lines 293-297.) Are there risks associated with not pursuing the Combined Projects?

A. Yes. If the company does not pursue the Combined Projects, it will be forgoing the opportunity for customers to acquire heavily-discounted resources in the near term, in exchange for greater reliance on near-term market transactions and waiting until after the expiration of PTCs to acquire zero-fuel-cost resources to meet growing energy and capacity needs. Contrary to parties' implication that there are no customer risks associated with forgoing the opportunity to procure PTC-eligible resources, there are risks associated with greater reliance on higher-cost FOT resources over the near term and greater reliance on other higher-cost resources over the long term—and those risks will be borne by customers.

Although parties point out the risks of the Combined Projects, they do not demonstrate that they are higher risk than the next best alternative. In contrast, the 2017

IRP and the economic analysis summarized in this testimony clearly demonstrates that the Combined Projects are least-cost, least-risk compared to all other alternatives, including the status quo alternative, which will result in increased reliance on higher-cost FOTs. Indeed, greater reliance on FOTs, in lieu of the Combined Projects, is expected to cost more under every combination of natural gas and CO_2 price scenario studied using the SO model and PaR with a forecast horizon extending through 2036.

Q. Have any parties to this case previously expressed concern over the risks associated with the continued reliance on market transactions?

A. Yes. When the company requested authority to terminate its RFP for 2016 resources, I understand that DPU noted that it "and others have for several years questioned the company's continued reliance on front office transaction (FOTs) (*i.e.*, short-term wholesale power purchases) in the company's bi-annual integrated resource planning process." *PacifiCorp's All Source Request for Proposals for a 2016 Resource*, Docket No. 11-035-73, Memorandum of the Division of Public Utilities at 4 (Jan. 14, 2013). DPU continued: "The termination of this RFP continues the company's reliance on FOTs and in the near- to intermediate-term may increase its reliance on these wholesale purchases together with the continued risks the Division associates with such reliance." *Id.* Similarly, OCS reiterated its concern "with the company's reliance on front office transactions in the long term." *PacifiCorp's All Source Request for Proposals for a 2016 Resource*, Docket No. 11-035-73, Memorandum of the Office of Consumer Services at 2 (Jan. 14, 2013).

I understand that DPU reiterated its concerns in the 2015 IRP docket. First, DPU noted: "For all of the years under review, the obligation or system requirement is greater than the available resources." *PacifiCorp's 2015 Integrated Resource Plan*, Docket No. 15-035-04, Division Comments on PacifiCorp's 2015 IRP at 16 (Aug. 25, 2015). DPU then observed that the company closes this resource deficit by relying "more heavily on FOTs to satisfy the difference" and that the "reliance on FOT transactions continues to be a concern to the Division and to other Utah parties." *Id.* According to DPU, the "reliance on the wholesale electric market could result in ratepayers facing greater price volatility and potentially loss of power except at very high prices in the event that the wholesale markets dry up due to environmental concerns and the possible closure of existing coal fired generation facilities, among other reasons." *Id.*

Q. Has any party provided meaningful analysis demonstrating that the status quo is less risky than pursuing the Combined Projects?

A. No. In asserting, without analysis, that the status quo yields superior outcomes, the parties discount the availability of a lower-cost, lower-risk alternative. To the extent they assume inaction is less risky than action, this assumption lacks either logical or factual support. There is nothing about inaction that makes it preferable to action when objectively considering relative risk. For the Combined Projects, nearly every modeling scenario results in customer benefits. Declining to pursue the Combined Projects results in a likely opportunity cost—that is, a likely customer loss.

The parties' recommendation against the Combined Projects is substantially more likely to achieve a less favorable outcome for customers in the form of increased costs and increased risk—a result inadequately justified by the preference for inaction over action. The company seeks to develop the Combined Projects now because the PTCs make this the least-cost, least-risk option to serve current capacity and energy needs. Inaction will forgo a valuable opportunity, and delaying the acquisition of least-cost resources in favor of higher-cost alternatives is not in the best interest of customers.

Q. Both Dr. Zenger and Mr. Mullins also argue that the company has an incentive to invest in the Combined Projects and suggest that this incentive is improperly driving the investment decision. (Mullins Direct, page 9, line 1-2; Zenger Direct, lines 117-119.) How do you respond?

A. These claims ignore the resource need discussed above. Mr. Mullins further supports this conclusion by citing the Averch-Johnson thesis, which theorizes that traditional rate-base and rate-of-return regulation biases a regulated firm, as compared to an unregulated one, toward more capital-intensive modes of production. Mr. Mullins' reliance on the Averch-Johnson thesis is misplaced, however, because there is considerable debate about whether the Averch-Johnson effect is real and, even if it is real, whether such an effect would be undesirable.[3]

This argument also ignores that the Combined Projects are more cost-effective than FOTs, even when including capital and run-rate operating costs. A higher-cost resource should not be selected merely to prevent an opportunity for shareholders to earn a rate of return.

[3] Charles F. Phillips, Jr., The Regulation of Public Utilities 892-93 (1993); see also James C. Bonbright et al., Principles of Public Utility Rates 362 (2d ed. 1988) ("[T]o the extent [the Averch-Johnson effect] exists, it could well be a more important influence for good than for poor performance[.]") (quoting Alfred E. Kahn, Applications of Economics to Utility Rate Structures, 101 Public Utilities Fortnightly 59 (Jan. 19, 1978)); id. ("To repeat: we find a paucity of data documenting the Averch-Johnson effects and instead find largely educated speculation."). A recent meta-analysis of scholarship concerning the Averch-Johnson effect concluded that it amounts to "an intellectual curiosity," and suggested that further efforts to discern an Averch-Johnson effect on regulated utilities be "abandoned in favour of more productive enterprises." Stephen M. Law, Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities, 6 INT'L J. OF ECON. & FIN. 41, 42, 52 (2014).

Q. Dr. Zenger also argues that if the Commission approves the Combined Projects here it will "likely lead to unwanted future utility actions." (Zenger Direct, lines 257-261.) Is this a valid concern?

A. No. Dr. Zenger's concern is about unwarranted resource development, and it is not clear how that could occur given the Commission's standard for reviewing the prudence of new resource acquisitions. The only scenario in which Dr. Zenger's fears could materialize—excessive capital investment at excessive ratepayer risk—requires the Commission to change its prudence review standard to ignore the reasonableness of the utility decision-making based on what the utility knew or should have known at the time of the acquisition decision.

Q. Dr. Zenger argues that the Combined Projects do not represent an "ordinary" resource acquisition. (Zenger Direct, lines 228-231.) Do you agree?

A. No. There is nothing novel or unique about the Combined Projects that require heightened review or a different standard for approval. Dr. Zenger does not challenge the fact that the company has an energy and capacity need in 2028. At the very least, the Combined Projects are an early acquisition. Dr. Zenger provides no support for the position that shareholders should bear greater risk when a utility prudently acquires a resource ahead of need. The Combined Projects do not present risks different than typical utility investments. The company's analysis shows that benefits from the Combined Projects accrue to customers in the near-term, well before the alleged 2028 capacity deficiency.

ECONOMIC ANALYSIS

Q. Mr. Mullins, Mr. Hayet, and Mr. Peaco argue that the company has overstated the economic benefits of the Combined Projects because natural gas prices in the base case scenario are too high. (Mullins Direct, page 23, lines 9-15; Hayet Direct, lines 271-297; Peaco Direct, lines 734-735) How does the company determine the forecasted natural-gas prices used for the economic analysis?

A. The medium (or base case) forecast is the company's OFPC, which uses observed forward market prices for the first 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by a reputable third-party expert. The low and high natural-gas price assumptions were also based on recent forecasts developed by reputable third-party experts. The company verified the reasonableness of the third-party forecasts by comparison to forecasts prepared by others, including the U.S. Department of Energy's Energy Information Administration.

Q. Is the OFPC used in the company's economic analysis the same forecast the Commission has used for ratemaking, setting avoided costs rates, and evaluating both demand- and supply-side resources?

A. Yes. The OFPC, which represents the medium-natural-gas-price case is the same forecast used for setting net power costs in the company's Utah rates. It is also used when the company calculates avoided cost prices paid to QFs, and evaluates the cost-effectiveness of demand-side and supply-side resources.

Q. Has the DPU previously testified regarding the reliance on the forward price curve when making resource decisions?

A. Yes. I understand that in Docket No. 12-035-102, the DPU testified that "future prices will likely be different from the forward price curve, but if the forecast is unbiased, *i.e.*, that it is equally likely that the actual future prices are higher or lower than the forecasted prices, [] the best approach is to simply act today on its forecast as the best indicator of future outcomes." *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources*, Docket No. 12-035-102, Pre-Filed Direct Testimony of Douglas D. Wheelwright on Behalf of Utah Division of Public Utilities at lines 326-330 (Mar. 5, 2013). DPU noted that if "one had information today that the longer-term future was likely to be different from the above forecast, then the above analysis could be invalidated by the additional information." *Id.* at 330-332. In this case, however, there is no additional information indicating that the longer-term future is likely to be different from the OFPC and therefore, according to the DPU's prior analysis, the "best approach" is to act today based on the OFPC.

Q. How does the company use each of the price-policy scenarios in its analysis?

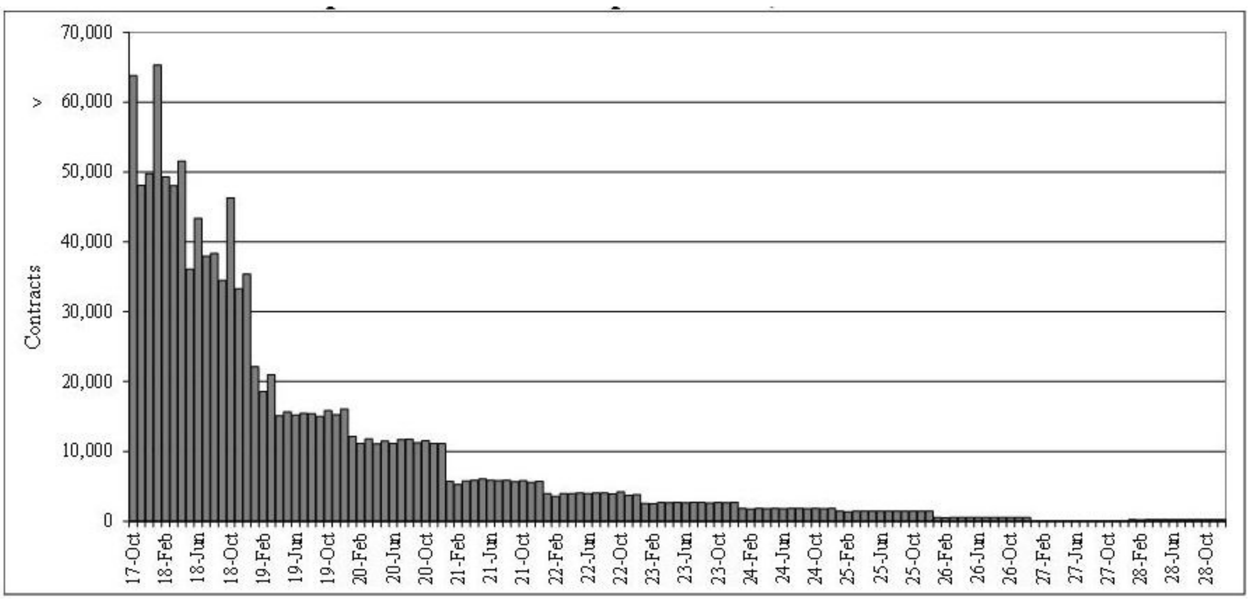
A. The price-policy scenario assuming medium natural-gas prices and medium CO_2 prices represents the central forecast, around which the impact of lower or higher price assumptions can be evaluated. In the company's updated economic analysis, the PVRR(d) net benefit of the Combined Projects derived from the central price-policy scenario is $177 million when calculated from projected nominal system costs through 2050. This outcome indicates that, when central price-policy assumptions are used, there is a reasonably sized cushion in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices and CO_2 prices end up lower than what is assumed in this scenario. The other price-policy scenarios are useful in quantifying how sensitive the PVRR(d) results are to these key assumptions and provide a foundation for judging risk. Importantly, however, the company's updated analysis now shows robust customer benefits in nearly all price-policy scenarios without even accounting for potential upside benefits not reflected in the economic analysis.

Q. Mr. Peaco compares the company's natural-gas price forecasts with NYMEX Henry Hub natural-gas futures through 2029 as of November 28, 2017, and concludes that the NYMEX forecast is "at least as important to consider" as the company's OFPC. (Peaco Direct, lines 722-723.) How do you respond?

A. Mr. Peaco's reliance on NYMEX futures is misguided because it relies solely on NYMEX Henry Hub natural-gas futures after 2022, which do not accurately capture market expectations for long-term natural-gas prices. Mr. Peaco 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 2-R shows NYMEX Henry Hub natural-gas open interest as of September 11, 2017.

Figure 2-R. NYMEX Henry Hub Natural Gas Futures
Open Interest as of September 11, 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 43,200. By 2023, open contracts average just over 2,600—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. Peaco claims the market outlook most closely aligns with the company's low natural-gas price forecast (*i.e.*, beyond 2024). 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. Has the DPU previously commented on the accuracy of the NYMEX futures contracts as a predictor for future prices?

A. Yes. I understand that, in a 2001 case, DPU discussed using NYMEX future contract prices to forecast avoided costs, but noted that the "future market is not very robust as very few trades are currently being made, thus the accuracy of the future's price is questionable." *In the Matter of Revisions to PacifiCorp's Tariff P.S.C.U. No. 43, Re: Schedule 72, Irrigation Curtailment Program Rider*, Docket No. 01-035-T04, Order (May 11, 2001).

Q. Mr. Mullins claims that the company's OFPC systematically overstates future market prices. (Mullins Direct, page 23, lines 9-15.) Please respond.

A. It is not reasonable to evaluate a forecast error for OFPCs. The company's OFPC is developed from a combination of market forwards on a given quote date and a long-term, fundamentals-based forecast as a proxy for forward prices beyond the period in which observed market forwards are not available. Forecast error is a measure of the difference between forecasted spot prices and actual spot prices. Comparing forward prices to actual spot prices is a misapplication of forecast error, because market forwards, which are used in the first 84 months of the OFPC, are observed, and not forecasted. Forward prices represent transaction prices occurring at the time of a future delivery date.

Market participants cannot transact on a spot price forecast. A spot price forecast merely represents a potential view of what prices will be at some point in the future. Market forwards reflect pricing for contracts that reflect the price, on a given quote date, at which buyers and sellers are transacting for future delivery.

Q. Mr. Mullins also claims that, "[i]f the OFPCs are reasonably accurate, one would expect PacifiCorp's price forecast to be an unbiased expectation of future spot prices." (Mullins Direct, page 27, lines 17-18.) Is this true?

A. Not necessarily. It is not strictly true that the forward prices will or should equal the expected price. Forward buyers and sellers are considering the trade-off between using a fixed forward price and simply waiting to transact at a risky spot price. To avoid arbitrage, these two have to be equal in present value, not in delivery-date value. In general, it is likely that spot prices are somewhat systematically risky, because demand for most commodities tends to move with the economy as a whole. Thus, it is unlikely that the appropriate discount rate for taking the present value of expected spot prices will be the risk-free rate that applies to discounting the forward price. For the two present values to be equal, the two future values have to be somewhat different.

Q. Mr. Mullins argues that the historical difference between the forecasted and actual spot prices indicates that there is a risk premium embedded in the OFPC. (Mullins Direct, page 28, lines 15-17.) How do you respond?

A. There may be a risk premium in the forward prices, which are used in the first 84 months of the OFPC, but that does not mean there is a risk premium further out in the forecasted period.

Moreover, Mr. Mullins' position here is contradicted by his testimony before the Oregon Commission earlier this year. In the company's annual power cost update proceeding, I understand that Mr. Mullins testified that the company's electric market transactions entered more than seven days before the settlement period (*i.e.,* hedging transactions) systematically generate customer benefits because the forward price curve is systematically *lower* than actual spot market prices. *See In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism,* OPUC Docket No. UE 323, ICNU/200, Mullins/8-10 (Aug. 2, 2017).

Q. Mr. Mullins claims that the Commission has expressed skepticism about the accuracy of long-term forecasting when it ordered QF contracts reduced to fifteen years. (Mullins Direct, page 32, lines 13-13.) Please respond.

A. This argument is unpersuasive. First, the company's avoided cost prices in Utah are set using the OFPC. Despite the Commission's concern over the inherent difficulty of forecasting, it has not implemented a policy requiring the company to use a lower forward price curve for avoided cost prices. Second, this argument ignores the fact that all long-term resource planning requires the use of long-term assumptions and forecasts. There is no doubt that there is uncertainty in future wholesale market prices, which is precisely the reason that the company has evaluated the Combined Projects across a range of different price-policy scenarios. And in nearly all scenarios, the Combined Projects produce net benefits for customers.

Q. Has UAE previously taken a position on price risk associated with long-term utility resource acquisitions?

A. Yes. In the same case where the Commission shortened the QF contract term, I understand that UAE's witness testified that "there is price risk associated with the acquisition of any long-term resource, including utility resources." *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA*

Power Purchase Agreements with Qualifying Facilities, Docket No. 15-035-53, Prefiled Direct Testimony of Kevin C. Higgins at lines 1465-169 (Sept. 16, 2015) (testifying on behalf of the Coalition, which included UAE). But UAE's witness argued the "price risk operates in both directions." *Id.* Thus, according to UAE, "[i]f the company's market price forecast is unbiased then the long-term price of a QF contract is as likely to be below future market prices as above them." *Id.* This prior position is fundamentally inconsistent with Mr. Mullins' testimony here that forecast prices are inherently overstated.

UAE's brief further explained that "[t]here is no way to predict whether" actual prices will be higher or lower than forecasts, but the risks are not symmetrical; the "downside risk of higher future prices is essentially limitless, while the realistic upside risk of lower future prices is relatively limited." *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities,* Docket No. 15-035-53, Post Hearing Brief of the Rocky Mountain Coalition for Renewable Energy at 8 (Dec. 9, 2015) (internal quotations omitted). Again, this prior UAE position undercuts Mr. Mullins' testimony here that forecast prices are consistently excessive. Moreover, given that the benefits of the Combined Projects increase as forecast natural-gas prices increase, UAE's prior position bolsters the case in favor of the Combined Projects.

Q. Based on the historical forecasting error, Mr. Mullins claims that the economic benefits of the Combined Projects may be overstated by approximately $411.2 million. (Mullins Direct, page 30, lines 3-12.) Is this a reasonable claim?

A. No. As I stated above, it is not reasonable to evaluate a forecast error for OFPCs, and therefore, it is not appropriate to apply an erroneous forecast error metric to long-term price assumptions. It is reasonable to assess a range of market outcomes, and this is precisely what the company has done by analyzing low and high natural-gas price scenarios that are based on recent forecasts developed by reputable third-party experts.

Q. Mr. Mullins further claims that two gas hedging contracts entered into in 2012 have been harmful to customers. (Mullins Direct, page 34, lines 15-16.) How do you respond?

A. I disagree. Mr. Mullins inappropriately reviews the performance of these two natural-gas hedges as financial trades. A financial trade is executed based on a speculative market view to earn a favorable return. A hedge is made to limit exposure to market volatility, not to earn a favorable return. The value of a hedge is not based on the fixed-price exposure of the hedge, but its effectiveness in limiting exposure to volatility in spot market prices. The effectiveness of these hedge transactions has no relevance to the validity of the company's OFPC, which reflects the best and unbiased representation of future market conditions available at the time the OFPC is produced, and has no relevance to the economic analysis of the Combined Projects.

Q. Mr. Hayet criticizes the company for updating the modeling assumptions for the Combined Projects without also updating modeling assumptions related to competing resource options, like solar resources. (Hayet Direct, lines 193-205). How do you respond?

A. As described above, the results of the 2017S RFP were used as a sensitivity in the selection of the shortlist for the 2017R RFP. Thus, the cost-and-performance assumptions related to solar resources have been fully updated commensurate with the updated modeling assumptions for the Combined Projects.

Q. Mr. Hayet was concerned that the 2017S results used in the sensitivity analysis may be incomplete because the solar RFP is still pending. (Hayet Direct, lines 675-677.) How do you respond?

A. While the 2017S RFP has not yet concluded, the data used in the company's solar sensitivities are tied to bids from a competitive solicitation process with robust market participation. Cost-and-performance assumptions used in the company's solar sensitivities are taken directly from this solicitation, which is being implemented with the oversight of an IE who has found that the process is being conducted in a clear and transparent manner. While the company has not established a final shortlist from the 2017S RFP, the sensitivity studies that rely on bids submitted into the RFP are not incomplete.

Q. Mr. Peaco claims that the company's analysis never considered smaller or larger quantities of wind resources that may be more economic than the 1,180 MW of wind included in the company's initial filing. (Peaco Direct, lines 410-415.) How do you respond?

A. Mr. Peaco is wrong. The company's portfolio development process used to evaluate the results of the 2017R RFP performed the exact analysis Mr. Peaco claims is lacking. As described in my supplemental direct testimony, the portfolio-development process allowed the SO model to select from any of the bids submitted to the 2017R RFP, which allowed the SO model to select smaller or larger quantities of wind. Ultimately, the model selected 1,170 MW of wind capacity as the least-cost bid portfolio based on the cost-and-performance of each bid.

Q. Mr. Peaco claims that the expected customer benefits are modest relative to the overall project costs and that there is very little certainty that customers will see significant, if any, cost savings. (Peaco Direct, line 316-318.) Mr. Hayet criticizes the Combined Projects because, under most scenarios, he claims they present modest benefits relative to the company's total revenue requirement. (Hayet Direct, lines 284-297.) Please respond.

A. First, Mr. Peaco mischaracterizes the relationship between the cost and benefits of the Combined Projects by comparing the up-front investment cost to the *net* benefits of the project. This artificially makes it appear that customer benefits are relatively small in relation to the investment required to deliver those benefits, when in fact, the gross benefits from the projects are actually greater than total project costs.

For instance, in the updated economic analysis, the PVRR(d) results calculated from the change in system costs through 2050 assuming medium natural-gas and medium CO_2 prices show a $177 million *net* customer benefit from the Combined Projects. This is based on present-value project costs, including changes to run-rate operating costs, totaling $1.47 billion. The present value of customer benefits, including federal PTC benefits, for this price-policy scenario is $1.65 billion, which is $177 million greater than the present value of project costs. In fact, the present value of customer benefits among all nine price-policy scenarios ranges between $1.30 billion and $2.06 billion. In nearly all scenarios, the present value of customer benefits exceed the present value of customer costs.

Second, the fact the total expected benefits are small relative to the company's total revenue requirement means little in this case. It is hard to imagine a resource decision that would provide customer benefits comparable to the total revenue requirement, which is apparently the metric Mr. Hayet has chosen to measure the reasonableness of the benefits.

Q. Mr. Mullins claims the company used supplemental GRID studies to develop unrealistic assumptions that are a "key driver in the economic benefits" of the Combined Projects. (Mullins Direct, page 41, line 7-14.) Is this true?

A. No. Contrary to Mr. Mullins' claim, the company's economic analysis supporting the Combined Projects does not include any assumptions derived from the supplemental GRID studies referenced by Mr. Mullins. The GRID studies and assumptions referred to by Mr. Mullins were used in the 2017 IRP, but not in the economic analysis included in this case.

Q. Does Mr. Mullins criticize the company's wind-integration charge assumptions used in the economic analysis supporting the Combined Projects?

A. Yes. Mr. Mullins notes that the company's wind-integration charge assumed in the economic analysis supporting the Combined Projects is \$0.63/MWh, when it estimated an integration cost of \$2.35/MWh in 2014. (Mullins Direct, page 50, lines 12-19.)

Q. Please respond.

A. The change in regulation-reserve costs is attributable to lower market prices, transmission congestion as a result of sizeable increases in solar capacity in the company's portfolio, and expanding the pool of regulation-reserve resources to include 30-minute ramping capability, none of which are disputed by Mr. Mullins. Thus, the wind-integration cost assumptions developed in the company's 2017 IRP are the most accurate estimate available.

Q. Mr. Peaco alleges that because there is no current price on carbon emissions, the scenarios with zero CO_2 price may be the most likely outcome. (Peaco Direct, lines 765-772.) Do you agree?

A. No. It is 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. Peaco claims that there is a production risk associated with the Wind Projects that impact customer benefits. (Peaco Direct, lines 979-982.) How has the company mitigated this risk?

A. Mr. Peaco does not testify that the company's wind-generation forecasts are invalid. Mr. Peaco simply asserts a potential risk to the overall economics if wind-generation output is reduced. This one-sided risk assessment fails to quantify the potential upside benefits if wind generation exceeds the assumed forecast used in the economic analysis. The company retained an independent expert to study and confirm the reasonableness of its capacity factor assumptions for specific projects bid into the 2017R RFP, and the findings of this review have been reflected in the economic analysis of specific proposals.

Q. Mr. Mullins argues that projected oversupply conditions in the West pose a risk to the Combined Projects that was not considered by the company. (Mullins Direct, page 19, lines 9-14.) Was this considered?

A. The company is aware of the development of renewable resources across the West. However, oversupply conditions are driven by the correlation between large numbers of intermittent renewable resources. For instance, wind resources in the Columbia River Gorge are often either mostly on or mostly off, with appreciable impacts on market prices in both directions. Similarly, solar resources across the West are strongly correlated with the position of the sun and thus each other, and likewise impact market prices in both directions.

While wind resources in Wyoming are correlated with each other, they are not strongly correlated with wind resources in the Columbia River Gorge or solar resources. The correlation of the proposed resources with the rest of the wind in the company's portfolio is already accounted for in the company's analysis, and the expected overall impact of renewable resource additions in the West is accounted for in the company's OFPC. Thus, the company's economic analysis reasonably accounts for potential oversupply conditions applicable to the proposed resources.

Moreover, the majority of the benefits associated with the Combined Projects are a result of fuel savings at PacifiCorp's plants, rather than market transactions based on the OFPC, particularly in the first few years. The costs associated with the company's fuel supply are less likely to be impacted by oversupply conditions in the manner suggested by Mr. Mullins.

Q. Mr. Hayet, Mr. Mullins, and Dr. Zenger also point out the risk associated with federal tax reform. (Mullins Direct, page 38, lines 14-19; Hayet Direct, pages 15-21; Zenger Direct, lines 272-274.) Has the risk associated with changes to the federal tax code been largely resolved?

A. Yes. The company's updated economic analysis described in my supplemental direct testimony accounts for the reduction in the federal income tax rate. And, despite the lower tax rate, the Combined Projects remain economic and the benefits have actually increased from the estimated benefits in the company's direct filing.

Q. Mr. Peaco questions the company's methodology for calculating the extended economic benefits beyond the 20-year study period used in the 2017 IRP. (Peaco Direct, lines 382-389.) Mr. Hayet also criticizes the calculation of extended benefits. (Hayet Direct, lines 593-594.) How do you respond?

A. The company's extrapolation methodology reasonably used the aggregate system benefits derived from the SO model and PaR over the period 2028 through 2036 (after the Dave Johnston plant retires). These data, based on how the Combined Projects affect forecasted system costs, are a reasonable proxy for projected long-term benefits associated with the Combined Projects. Mr. Peaco's criticism of this methodology simply states that the company's approach "can yield results that are problematic due to the timing of new resource additions[.]" (Peaco Direct, lines 386-387.) Mr. Peaco never explains with those problematic results are, or even if they occurred. Mr. Peaco's criticism is without merit.

Q. Mr. Hayet also argues that the benefits reflected in the repowering sensitivity are likely overstated. (Hayet Direct, lines 633-637.) What is the basis for Mr. Hayet's claim?

A. Mr. Hayet claims that the company did not provide any analysis that the benefits of the Combined Projects would increase significantly when combined with repowering and measured through 2050. Mr. Hayet argues that the methodology the company used in the repowering docket to model the customer benefits from 2037 to 2050 overstates the value of the incremental generation from the repowered facilities because there is no reason to expect the value of the incremental energy before 2037 (when repowering will produce 550 GWh) will be a reasonable proxy for the value after 2037 (when repowering will produce 3,300 GWh).

Q. Please respond.

A. The updated repowering sensitivity performed above demonstrates that the benefits of the Combined Project increase in combination with the repowering project when measured through 2036. Thus, without the extrapolation that Mr. Hayet criticizes, repowering increases customer benefits by $171 million under the medium natural-gas price, medium CO_2 price scenario, and by $159 million under the low natural-gas price, zero CO_2 price scenario as measured by risk-adjusted PaR results.

Q. Mr. Mullins claims that the use of the levelized fixed cost for the Transmission Projects understates the total costs because the transmission assets have longer useful lives than the 20-year study period used to evaluate the economic benefits of the Combined Projects. (Mullins Direct, pages 48-49.) Mr. Peaco makes a similar argument. (Peaco Direct, lines 367-379.) How do you respond?

A. First, Mr. Mullins acknowledges that levelized costs are regularly used to evaluate different generation resources with different lives. But Mr. Mullins claims that the use of levelized costs is not appropriate when comparing transmission assets because transmission lines do not produce electricity. Mr. Mullins provides no further explanation and, on its face, this argument makes no sense. If levelized costs are a reasonable metric for comparing competing resources with different useful lives, there is no reason to arbitrarily exclude transmission resources.

Second, Mr. Peaco and Mr. Mullins both claim that the company's economic analysis understates the total costs of the Transmission Projects because the economic analysis does not cover the 62-year useful life of the Transmission Projects. But, as Mr. Peaco concedes, customers will receive the benefits of the Transmission Projects beyond the study period used in this case.

Q. Mr. Peaco argues that a relatively small reduction in the amount of wind resources that the company acquires will largely eliminate the customer benefits of the Combined Projects. (Peaco Direct, lines 582-585.) How do you respond?

A. The company has established its final shortlist from the 2017R RFP and is on track to execute definitive agreements with winning bidders by mid-April 2018. At this stage, the amount of new wind resource capacity that maximizes customer benefits has been established.

Q. Mr. Davis also claims that the Wind Projects could add to the existing constraints on the transmission system and require the uneconomic curtailment of existing thermal resources. (Davis Direct, lines 220-231.) How do you respond?

A. Incremental energy from the Wind Projects could contribute to congestion and require redispatch of other system resources. Redispatch can reduce NPC benefits at times where increased congestion would restrict the otherwise economic use of other system resources to serve load or as a source for wholesale-market sales. The economic analysis summarized in my direct testimony and the updated economic analysis summarized in my supplemental direct testimony captures the cost of redispatch in the economic analysis.

CONCLUSION

Q. Please summarize the conclusions of your rebuttal testimony.

A. The results of the 2017R RFP confirm that the Combined Projects are the least-cost, least-risk resources available to serve the company's customers. The substantial volume of bids submitted into the 2017R RFP produced competitive project costs, allowing the company to obtain greater wind generating capacity at lower overall capital costs, with increased net benefits for customers. The Combined Projects show net customer benefits under all price-policy scenarios through 2036 and in seven of nine scenarios through 2050. The company's updated sensitivities further demonstrate that the Combined Projects are not displaced by solar resources that bid into the 2017S

RFP, and that the economics of the Combined Projects become more favorable when combined with wind repowering.

Despite claims to the contrary, PacifiCorp has near-term and long-term resource needs that can be partially met with heavily discounted Wind Projects that are lower cost than all other near-term and long-term resource alternatives. The Combined Projects are an element of PacifiCorp's least-cost, least-risk resource plan and there is nothing novel or unique about these resources that justifies unprecedented cost-recovery treatment that assigns all risk to the company. The company's long-standing methodology to develop its OFPC produces the best representation of future market prices for the central forecast, and alternative price-policy scenarios provide a reasonable foundation for judging risk.

Q. Does this conclude your supplemental direct and rebuttal testimony?

A. Yes.