Docket No. 20000-520-EA-17
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

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Supplemental Rebuttal Testimony of Rick T. Link

March 2018

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

A. Yes.

## PURPOSE AND SUMMARY OF SUPPLEMENTAL REBUTTAL TESTIMONY

**Q. What is the purpose of your supplemental rebuttal testimony in this proceeding?**

A. My testimony supports the company's application for certificates of public convenience and necessity ("CPCNs") to construct the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") and to construct or acquire the Ekola Flats, TB Flats I and II, Cedar Springs, and Uinta projects, which are the four new wind resources ("Wind Projects") included on the final shortlist of the 2017R Request for Proposals ("2017R RFP") (collectively, the "Combined Projects"). Specifically, my testimony responds to the March 2, 2018 testimony filed by Bryce J. Freeman, on behalf of the Wyoming Office of Consumer Advocate, Nicholas L. Phillips, on behalf of the Wyoming Industrial Energy Consumers ("WIEC"), Mark D. Milburn, on behalf of Rock Creek Wind, LLC ("Rock Creek"), Gregory F. Jenner, on behalf of the Interwest Energy Alliance, Kenneth G. Lay, on behalf of the Northern Laramie Range Alliance, and Kristy V. Thompson, on behalf of the Rocky Mountain Sheep Company.

**Q. Please summarize your testimony.**

A. I address criticisms of PacifiCorp's 2017R RFP modeling and results and the company's economic analysis showing significant customer benefits associated with the Combined Projects. In response to claims that the Combined Projects may not be the least-cost, least-risk resource option, I also summarize the economic analysis used to finalize PacifiCorp's 2017S Request for Proposals (2017S RFP) bid-selection process. My rebuttal testimony demonstrates that:

- As supported by independent experts that were appointed, retained, and managed by two different state regulatory commissions, the 2017R RFP was fair, transparent, and unbiased.
- These independent experts found that the bids selected to the 2017R RFP final shortlist represent the top offers that are viable under current transmission planning assumptions, and one of the experts concluded that the final shortlist should result in significant savings for customers.
- The company has performed over 1,300 20-year simulations of PacifiCorp's system to thoroughly evaluate how the net benefits of the Combined Projects are affected by a broad range of variables and uncertainties.
- While solar resources may provide customer benefits, contrary to claims from certain parties, solar resource bids submitted into the 2017S RFP are not a superior resource alternative to the Combined Projects.
- Solar resources are best viewed as an incremental opportunity, not as an alternative to the Combined Projects.
- During the evaluation of bids in the 2017S RFP, PacifiCorp analyzed valuation risks that are unique to the procurement of solar resources and determined that solar resource costs are likely to continue to fall.
- Given these solar resource-valuation risks, expected cost declines, and availability of the 30-percent investment tax credit ("ITC") for solar projects coming online as late as 2021, PacifiCorp does not need to act now and has decided not to select any of the solar power-purchase agreement ("PPA") bids

to the 2017S RFP final shortlist.

- PacifiCorp will continue to assess potential economic benefits from solar-resource opportunities in the 2019 Integrated Resource Plan ("IRP"), including a thorough review of valuation risks with full stakeholder engagement, to determine whether a new competitive solicitation process for projects capable of achieving commercial operation by the end of 2021 will provide customer benefits.
- In contrast, the phase-out of production tax credit ("PTC") benefits that are available for qualifying wind projects occurs sooner than the ramp down of ITC benefits that are available for solar resources, which requires that PacifiCorp act now to deliver the new wind and needed transmission investments that will produce both near-term and long-term benefits for customers.

**2017R RFP MODELING AND RESULTS**

**Q. WIEC and Rock Creek both claim that the 2017R RFP was unfair and biased (*see, e.g.*, Phillips Corrected Supp. Response, page 9, lines 9–15; Milburn Direct Supp., page 11, lines 7–14). What is your general response to this contention?**

A. I disagree. More importantly, WIEC's and Rock Creek's assertions are directly contrary to the conclusions of the independent evaluators ("IEs") who monitored the 2017R RFP. Both IEs provided their own independent analysis and carefully scrutinized the process and results. And both IEs concluded that the 2017R RFP was transparent, fair, and unbiased.

**Q. Please provide more detail on the role of the IEs.**

A. The 2017R RFP was overseen by two IEs—one appointed by the Public Utility

Commission of Oregon ("Oregon Commission") and retained by PacifiCorp, and one appointed and retained by the Public Service Commission of Utah ("Utah Commission"). In accordance with the statutes, rules, and policies in Oregon and Utah, the IE is an *independent* expert appointed and managed by the commissions (not PacifiCorp) to ensure that the RFP process was conducted in a fair and unbiased manner and to ensure that the final shortlist projects are reasonable and consistent with the modeling results used to evaluate bids.

In the 2017R RFP, both IEs were involved from the beginning—providing feedback and recommendations regarding the design and content of the 2017R RFP and actively participating in every stage of the RFP. For its part, PacifiCorp ensured that the IEs had complete and unrestricted access to all information related to the 2017R RFP and kept both IEs informed of developments as they occurred.

**Q. Did the IEs provide an assessment of PacifiCorp's benchmark resources bid into the 2017R RFP (*i.e.*, TB Flats I and II, Ekola Flats, and McFadden Ridge II)?**

A. Yes. Because the 2017R RFP included benchmark resources, both IEs provided detailed assessments of the benchmark bids to ensure that they were reasonable and would not bias the solicitation in favor of utility-owned resources. The benchmark review process occurred before any other bids were received to provide additional assurance that the benchmarks were not provided an unfair advantage.

**Q. Did the IEs' review confirm the reasonableness of the benchmark bids?**

A. Yes. As described in my second supplemental testimony, the Utah IE concluded that PacifiCorp provided detailed information related to the benchmarks that exceeded industry standards, that the cost estimates were reasonable, and that the review, assessment, and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward perception of bias (Link Second Supp., page 28, line 4–21).

The Oregon IE also conducted a thorough assessment of the benchmarks, noting that when "assessing a utility's own bids in response to the RFP, our greatest concern is that the utility will incorporate cost estimates that have been aggressively estimated and do not characterize the costs of the project accurately." (Independent Evaluator's Final Report on PacifiCorp's 2017R Request for Proposals at 10 (Feb. 16, 2018) (hereinafter "Oregon IE Report")[1]). To make its assessment, the Oregon IE "looked at a detailed breakdown of each of the benchmarks costs to determine if any items have been improperly omitted from the cost calculation, and at overall capital cost levels by comparing them to publicly-available data on recent wind generation capital costs." (Oregon IE Report at 10). This "comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors." (Oregon IE Report at 10). The Oregon IE ultimately found that the benchmarks were acceptable based on three items:

- First, the benchmarks were not deliberately underpriced through omission of any capital cost components.
- Second, the benchmark capital and operating costs appeared reasonable when compared with public data on U.S. wind projects.
- Third, the capacity factors of the benchmarks were reasonable when compared

[1] The company provided a highly confidential version of the Oregon IE Report as part of Replacement Exhibit RMP__(RTL-8SS). Rock Creek Exhibit No. 1001.1 is the non-confidential version of the Oregon IE Report. The company's references to the Oregon IE report in its supplemental rebuttal testimony refer exclusively to the non-confidential portions.

with public data and were supported by credible third-party analysis.

(Oregon IE Report at 10–11).

**Q. Did the IEs provide any overall conclusions related to the 2017R RFP?**

A. Yes. The Oregon IE recommended that the Oregon Commission approve PacifiCorp's final shortlist based on the following conclusions:

- The selected bids represent the top offers that are viable under current transmission planning assumptions and provide the greatest benefits to ratepayers.
- The selected bids represent the best viable options from a competitive perspective, based on the 59 bid options presented.
- The IE's independent analysis confirmed that the selected bids were reasonably priced and, while not the lowest-cost offers, were the lowest-cost offers that were viable under current transmission planning assumptions. The IE's independent analysis included its own cost models for each bid option and a review of PacifiCorp's models.
- The IE took special care to confirm the selection of PacifiCorp's benchmark resources. The IE confirmed the accuracy of the benchmark costs and scoring. The IE noted that the benchmark bids were disciplined by the fact that a third-party bidder submitted a competing offer for a build-transfer agreement ("BTA") for benchmark projects.
- The IE confirmed that the 2017R RFP aligns with the 2017 IRP.

(Oregon IE Report at 2–3).

The Utah IE also supported the final shortlist projects based on the following conclusions:

- The 2017R RFP was fair, reasonable, and generally in the public interest. (Final Report of Merrimack Energy Group, Inc. to Utah Public Service Commission, PacifiCorp Renewable Request for Proposals at 70 (Feb. 2018) (hereinafter "Utah IE Report")[2]).
- The bid evaluation and selection processes were designed to lead to the acquisition of wind-generated electricity at the lowest reasonable cost based on the detailed state-of-the-art portfolio evaluation methodology used, the steps taken to achieve comparability between utility cost-of-service resources and third-party firm priced bids, the flexibility afforded bidders via a range of eligible resource alternatives, and the attempt to allow for equal terms for PPA and BTA resources. (Utah IE Report at 71).
- PacifiCorp's modeling demonstrates that the Combined Projects "should result in significant savings for customers." (Utah IE Report at 83). Further, because PTCs will flow through to customers in the first ten years, the "near-term benefits to customers should be significant." (Utah IE Report at 83).

**Q. Did PacifiCorp refine its economic modeling for purposes of developing the final shortlist for the 2017R RFP?**

A. Yes. As explained in my supplemental direct testimony, when comparing bids in the 2017R RFP portfolio development phase, for self-build and BTA bids, PTC benefits were applied on a nominal basis rather than a levelized basis to better reflect how the

[2] The highly confidential version of the Utah IE Report is attached to my testimony as Highly Confidential Exhibit No. __(RTL-1SR). Rock Creek Exhibit No. 1001.2 is the non-confidential version of the Utah IE Report. The company's references to the Utah IE report in its supplemental rebuttal testimony refer exclusively to the non-confidential portions.

PTC benefits flow through customer rates (Link Supp. Direct, page 25, line 11 to page 26, line 10). This refinement was used only in the portfolio development phase of the analysis and impacted only the System Optimizer ("SO") model and Planning and Risk model ("PaR") results through 2036. This modeling refinement had no impact on the nominal revenue requirement calculations that were also reported in my supplemental direct and second supplemental direct testimony.

**Q. Did you continue to use levelized capital costs during the portfolio development phase?**

A. Yes.

**Q. Is the treatment of PTCs and capital costs consistent with how PacifiCorp has analyzed specific resource decisions using its IRP models in the past?**

A. Yes. When the company has historically conducted economic analysis of specific resource decisions, it treats costs that are not spread over the life of the asset on a nominal basis. Typically, this means that capital costs are levelized, while other costs, such as operations and maintenance ("O&M") costs, are nominal. The company used this approach without controversy when it requested CPCNs to install emission control equipment at its Jim Bridger Unit 3 and Unit 4 coal units and when it conducted coal-plant analysis in its IRPs. The refined modeling used here simply conforms the treatment of PTCs to the treatment of other costs and benefits that are not spread out over the life of the asset.

**Q. Does PacifiCorp intend to model PTCs in this manner in its IRPs?**

A. Yes. Because modeling PTCs on a nominal basis better reflects how they are treated in rates, PacifiCorp intends to use this approach in future IRPs.

**Q. Did the IEs overseeing the 2017R RFP object to PacifiCorp's refined modeling?**

A. No. Both IEs overseeing the 2017R RFP were aware of PacifiCorp's decision to model PTC benefits on a nominal rather than levelized basis, and neither concluded that the refinement biased the bid evaluation results. In fact, the IE sensitivity that I described in my supplemental testimony (Link Supp., page 11, line 1 to page 12, line 2) was designed to specifically test whether the refined modeling of PTC benefits unreasonably biased the resource selection. The Oregon IE's report supports the conclusions I reported regarding the IE sensitivity. According to the Oregon IE, levelizing the PTC benefits caused the SO model to select PPAs instead of self-build and BTA bids. (Oregon IE Report at 30). But "looking at the actual flow of cost recoveries, treating both PTCs and costs as incurred" out through 2050, demonstrated that each portfolio produced virtually identical net benefits. (Oregon IE Report at 32). The Oregon IE also noted that the PPA portfolio was more expensive in the early years. (Oregon IE Report at 32). Thus, PacifiCorp's refined PTC modeling did not unreasonably bias the selection of resources. The Oregon IE also specifically noted that the PTC-modeling refinement "had no impact on winning projects selected in this RFP" because several of the PPAs that were selected in the IE sensitivity were ultimately non-viable projects (Oregon IE Report at 5).

**Q. Did the Utah IE also address the treatment of PTCs in the portfolio development phase of the 2017R RFP?**

A. Yes. The Utah IE noted a concern that the PTC modeling could produce a bias in favor of utility-owned resources "if only a portion of the capital costs associated with the benchmarks and BTAs are recovered during the 20-year evaluation period, since these projects have a 30-year life and capital cost recovery period." (Utah IE Report at 62). In response, the Utah IE described the additional analysis provided by the company, along with several meetings with the IEs to discuss this issue. The Utah IE observed in his report that PacifiCorp "refuted the basis for evaluating PTCs on a levelized cost basis since [PacifiCorp] would flow through all the customer costs in the near-term." (Utah IE Report at 62). Further, according to the Utah IE, PacifiCorp "also provided a 30-year analysis of the costs and benefits of the initial portfolio [*i.e.*, the portfolio with utility-owned resources] and the updated portfolio [*i.e.*, the portfolio with PPAs]. . . to demonstrate that the original portfolio would still provide greater benefits over a 30-year timeframe." (Utah IE Report at 62).

When PacifiCorp presented its final shortlist to the IEs, the Utah IE provided additional discussion of this issue:

> PacifiCorp also addressed two of the IEs concerns raised in discussions on shortlist evaluation and selection. The first issue dealt with the application of the PTCs in the evaluation methodology. As noted, PacifiCorp's analysis assumes that the PTC inputs to the SO model would be based on nominal dollar values since the actual benefits would be flowed through to customers. The Oregon IE requested a sensitivity where the PTC benefits produced by BTA and benchmark options would be levelized over the full 30- year life of the project. A second issue raised by the IEs was whether the term of the analysis through 2036 (approximately 16 years) and the real levelized cost treatment for capital revenue requirements adequately reflects all the capital costs associated with utility ownership options over a thirty-year project life. In response, PacifiCorp completed an analysis of the expected benefits and costs through 2050 comparing the results of PacifiCorp's selected portfolio and the IE sensitivity case. In its presentation, PacifiCorp concluded that the PVRR(d) benefits through 2036 from the final shortlist portfolio total $343 million and the benefits from the IE Sensitivity with the PPA included in the bid portfolio total $277 million. Through 2050, the benefits from the final shortlist bid portfolio of $223 million are closely aligned with the IE

> Sensitivity bid portfolio that provides an estimated $224 million in benefits through 2050. The revised shortlist portfolio provides greater near-term benefits.

(Utah IE Report at 65).

**Q. Did the Utah IE provide any conclusions related to whether the self-build or BTA bids received a preference as a result of PacifiCorp's modeling?**

A. Yes. The Utah IE concluded that the results of the IE sensitivity (discussed above) "indicated that there did not appear to be an inherent advantage associated with a utility-ownership bid due to the shorter evaluation period for purposes of evaluating and selecting a portfolio of resources." (Utah IE Report at 75). The IE explained that the "net benefits approach used may eliminate the costs for a longer-term resource but also eliminates the revenue side of the equation, which would likely be escalating over time." (Utah IE Report at 75). Thus, the company's modeling "allows for a consistent and fair evaluation of bids of different technologies and terms and is a reasonable tool for initial evaluation of bids." (Utah IE Report at 75).

**Q. Mr. Phillips claims that the use of nominal pricing for the PTCs and levelized pricing for the capital costs create an improper mismatch that biased the resources selected in the 2017R RFP, (Phillips Corrected Supp. Response, page 9, lines 9–15; Phillips Corrected Supp. Response, page 6, lines 10–16). Do you agree?**

A. No. Moreover, neither of the independent experts that monitored the 2017R RFP agree either, as discussed above. Mr. Phillips claims that the use of nominal PTC pricing together with levelized capital costs improperly reduced the net present value ("NPV") of utility-owned resources making it more likely that the SO model would select self-build or BTA bids (Phillips Corrected Supp. Response, page 10, lines 9–17). But the lower NPV cost of utility-owned resources corresponds to how the PTC benefits pass through to customers; therefore any benefit to self-build and BTA bids is consistent with how the costs and benefits are treated in ratemaking and is not due to PacifiCorp's modeling refinements.

It is also disingenuous for Mr. Phillips to imply that PacifiCorp's modeling change was improperly motivated when he argues that the nominal revenue requirement results, which have always applied PTCs on a nominal basis, "most closely depict how project costs and benefits will pressure rates." (Phillips Corrected Supp. Response, page 6, lines 21–23).

**Q. Did Mr. Phillips refute the IE sensitivity analysis presented in your supplemental direct testimony and discussed at length in the IE reports?**

A. No.

**Q. Mr. Phillips also claims that the company improperly used "real" levelization instead of uniform levelization (Phillips Corrected Supp. Response, page 7, lines 17–20). Is this true?**

A. No. I explained in my direct testimony that it is important to levelize capital revenue requirement in the SO model and PaR to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates (Link Direct, page 26, lines 21 to page 27, line 17). As noted by Mr. Phillips, the company uses an inflation-adjusted real-levelized method rather than using a uniform-levelization method. The inflation-adjusted real-levelized method more closely aligns with the fact that benefits for capital investments generally increase over time. Consequently, and similar to the problems associated with using a nominal revenue requirement approach in the SO model and PaR, the application of a uniform-levelization method would also create potential distortions in resource selections for capital-intensive assets that have different lives and in-service dates.

**Q. Mr. Phillips suggests that the Wind Projects are higher risk than PPAs because customers are insulated from risks when the company executes PPAs, whereas customers bear risks for utility-owned resources (*e.g.*, the risk of construction cost over-runs) (Phillips Corrected Supp. Response page 12, lines 13–17). How do you respond?**

A. I disagree. Mr. Phillips ignores the fact that customers also receive upside benefits for utility-owned resources that they do not receive under a PPA. For example, I described in my previous testimony the potential upside benefits associated with renewable energy credits ("RECs"), reduced O&M costs, and increased energy production (Link Second Supp. Direct, page 14, line 13 to page 15, line 17; Exhibit RMP__(RTL-2SD); *see also* Teply Rebuttal, page 14, lines 1–19). In each of these cases, customers will receive the increased benefits because of the nature of cost-of-service ratemaking. Under a PPA structure, on the other hand, project owners receive all the upside benefits. PPAs can provide some amount of certainty, but that certainty can both benefit and harm customers.

Moreover, a utility self-build or BTA project provides substantial long-term benefits that customers never receive under a PPA. Once a PPA term expires, customers walk away with nothing. If the utility owns the resource, however, customers will continue to receive the benefits of that resource for as long as it operates and even after the resource is no longer operational, customers retain the value associated with the land and facilities that have lives that extend beyond the life of the generating resource.

To use Mr. Phillips's example of a home mortgage, under a utility-owned bid, customers pay the mortgage and, after 30 years, they own the home. Under a PPA, customers pay the mortgage and, after 30 years, customers have nothing.

**Q. Mr. Phillips also complains that he had insufficient time to review the Combined Projects (Phillips Corrected Supp. Response, page 5, lines 7–18). Do you agree?**

A. No. Parties have had eight months to review the proposed resource decision in this case. Over that time, the Aeolus-to-Bridger/Anticline line has not changed in any material way. While it is true that the results of the 2017R RFP were disclosed fairly recently, PacifiCorp's modeling has remained virtually unchanged, and three of the four resources included in the company's initial filing were also included in the final shortlist.

**Q. Mr. Milburn disputes the fact that bids with interconnection queue positions lower than Q0712 were considered non-viable (Milburn Direct Supp., page 7, line 19 to page 8, line 1). How do you respond?**

A. As explained by Mr. Rick A. Vail, bids with generator interconnection queue positions lower than Q0712 required the construction of Gateway South for interconnection and therefore could not be completed by 2020. Mr. Milburn's claim that the company could have allowed projects with higher interconnection queue numbers (*i.e.*, projects with lower interconnection queue positions) to bypass projects with lower interconnection queue numbers (*i.e.*, projects with higher interconnection queue positions) is contrary to PacifiCorp's open access transmission tariff ("OATT").

**Q. Did the IEs address this issue?**

A. Yes. Both independent experts agreed with PacifiCorp's assessment that projects with interconnection queue positions lower than Q0712 were non-viable. The Oregon IE explained that PacifiCorp's "transmission arm, which assesses interconnection costs, must, by law, assume that each queue project is interconnected in order received so each project assumes that all projects ahead of it in the queue are interconnected." (Oregon IE Report at 32). Thus, "[a]s more projects in the Wyoming area are interconnected it puts more strain on the transmission system until eventually major upgrades such as the Gateway West and South projects are needed." (Oregon IE Report at 32). In this case, the major upgrades were required for all projects with queue positions lower than Q0712. The Oregon IE concluded that it "understand[s] and appreciate[s] PacifiCorp's position and do[es] not disagree with their transmission department's findings (beyond noting the obvious fact that many projects will likely drop out of the queue and that actual interconnection costs will differ from projected)." (Oregon IE Report at 35). According to the IE, "[t]o go forward with projects that cannot meet the proposed online date without major accelerated transmission investment would not seem to be the wisest course of action." (Oregon IE Report at 35).

**Q. Is the fact the IE disagrees with Mr. Milburn's claim particularly notable?**

A. Yes. Mr. Milburn attached both IE reports to his testimony and "encouraged the Commission to carefully review these reports[.]" (Milburn Direct Supp., page 11, lines 12–14). Mr. Milburn's apparent reliance on the IEs undermines his own credibility when considering that both independent experts reached the same conclusion, which is the opposite of Mr. Milburn's conclusion.

**Q. Mr. Milburn claims that the 2017R RFP "may have been a waste of resources for many stakeholders" because bids with an interconnection queue position lower than Q0712 were considered non-viable (Milburn Direct Supp., page 5, lines 9–12). Is this a fair characterization of the 2017R RFP?**

A. No. Because PacifiCorp's transmission is constrained, particularly in eastern Wyoming, PacifiCorp initially proposed limiting participation in the 2017R RFP to generators with completed interconnection studies. At the recommendation of the IEs, this restriction was changed to generators who had begun the interconnection study process. *See Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources*, Utah PSC Docket No. 17-035-23, Hearing Transcript, page 56, lines 4–10 (Sept. 19, 2017). This change increased the number of projects that could bid into the 2017R RFP, which resulted in robust participation, including numerous bids that were not dependent on the construction of the Aeolus-to-Bridger/Anticline line. Although transmission constraints ultimately rendered some bids non-viable, neither IE indicated that the 2017R RFP process was a waste of time.

**Q. Mr. Milburn also claims that PacifiCorp has made it "seemingly impossible" for projects that were not selected in the 2017R RFP to "arrange alternative off-take or financing" if the project relies on interconnection to the company's eastern Wyoming transmission system (Milburn Direct Supp., page 7, lines 15–20). How do you respond?**

A. Mr. Milburn's complaint has no relevance here. Essentially, he complains that his project has a relatively high interconnection queue number (*i.e.*, a lower-priority interconnection queue position) and therefore requires additional interconnection facilities over-and-above the construction of the Aeolus-to-Bridger/Anticline line. But any inability to obtain financing for Rock Creek results from the fact it requested interconnection for the project after other projects were already in the queue. As explained by Mr. Vail, PacifiCorp must manage its interconnection queue consistent with the terms and conditions of its OATT. The OATT does not allow a project like Rock Creek to cut ahead of other projects that have priority positions in the queue.

**Q. Mr. Milburn argues that interconnection costs were not properly allocated to the projects that triggered them in the portfolio evaluation phase of the 2017R RFP (Milburn Direct Supp., page 9, lines 7–9). Is this true?**

A. No. PacifiCorp's bid-selection process and the associated economic analysis did in fact appropriately assign interconnection network upgrade costs to the specific projects that will trigger these costs. Mr. Milburn provides no basis for his unsubstantiated claim in his direct supplemental testimony. In response to a data request, Rock Creek admitted that it had no direct information about how the company's evaluation was actually performed, and that it made this claim based on certain information contained within the 2017R RFP and posted responses to bidder questions.

**Q. Did either of the IEs indicate that the interconnection costs were not properly allocated to the projects that triggered them?**

A. No.

**Q. Mr. Milburn contends that PacifiCorp did not evaluate all of the good faith proposals it received (Milburn Direct Supp., page 10, lines 4–15). Is this true?**

A. No. Rock Creek offered to sell development rights, which included land leases, wind-resource data, its position in the PacifiCorp generator interconnection queue, surveys, and other development work for a wind site. The introduction to the 2017R RFP explains that PacifiCorp was seeking proposals for competitively priced new or repowered existing wind projects. Rock Creek's proposal did not include all of the equipment necessary to deliver a new wind project (*i.e.*, wind turbines). PacifiCorp did not consider or evaluate *any* offers for development rights that did not represent a fully developed wind project during the 2017R RFP.

Mr. Milburn was provided a written explanation of why Rock Creek's proposal to sell development rights was non-conforming. Moreover, both IEs agreed with the company's decision to reject non-compliant bids (Oregon IE Report at 14–15; Utah IE Report at 73). PacifiCorp is currently in the process of returning bid fees for non-compliant bids submitted into the 2017R RFP, including Rock Creek's bid fee for its proposal to sell development rights.

**Q. Mr. Milburn claims that the Oregon and Utah IE reports describe "additional concerns about whether the RFP results provide the least-cost, least-risk solution for customers." (Milburn Direct Supp., page 11, lines 7–14). Is this a fair characterization of the IE reports?**

A. No. Mr. Milburn does not identify these "additional concerns," but as described in detail above, both IEs agree with PacifiCorp's final shortlist of projects, fundamentally undermining Rock Creek's claim that the 2017R RFP process was unfair or resulted in the selection of higher-cost, higher-risk resources than were otherwise available. Most notably, the very IE reports that Mr. Milburn urges the Commission to study undermine each of his specific complaints.

## ECONOMIC ANALYSIS

**Q. Mr. Phillips argues that the Commission should give greater weight to the nominal revenue requirement analysis, which was performed through 2050 (Phillips Corrected Supp. Direct, page 7, lines 1–6). Do you agree?**

A. No. Both types of analysis—the system modeling results through 2036 and the nominal revenue requirement results through 2050—are useful in assessing the economics of the Combined Projects. The system modeling results provide a view of economic analysis that is consistent with the planning period and approach used to identify a least-cost, least-risk preferred portfolio in the IRP. This type of analysis was used to identify new wind and transmission projects as an element of PacifiCorp's least-cost, least-risk plan in the 2017 IRP and has been used to evaluate past resource acquisitions and plant investments. For instance, the same IRP models used to evaluate the Combined Projects in this proceeding, configured to simulate PacifiCorp's system over a 20-year time frame with the application of levelized capital costs and nominal non-capital costs, were used to support the company's acquisition of the Chehalis combined-cycle plant, support selection of the Lake Side 2 combined-cycle plant through an RFP process, and to support the company's CPCN application for the installation of selective catalytic reduction equipment at Jim Bridger Unit 3 and Unit 4.

The nominal revenue requirement analysis provides a sense of how the Combined Projects might impact customer rates, relative to alternative resource procurement scenarios, over time. While an extension of system benefits associated with the Combined Projects through 2050 enables a present-value revenue-requirement differential ("PVRR(d)") to be calculated, as with any long-term study, longer-term results are increasingly more difficult to project. Moreover, I noted in my second supplemental direct testimony that the long-term extrapolation of system benefits used in the nominal revenue requirement analysis is conservative because the extrapolation approach yields projected benefits that do not reach the levels observed in the model in 2036 until 2047.

**Q. Mr. Phillips claims that the economics of the Combined Projects are no better than when originally proposed (Phillips Corrected Supp. Response, page 27, lines 18–20). Do you agree?**

A. No. Mr. Phillips concedes that PacifiCorp's updated nominal revenue requirement analysis shows that the benefits under the medium natural gas, medium $CO_2$ scenario increased from $137 million to $167 million—an increase of over 20 percent (Phillips Corrected Supp. Response, page 28, line 20 to page 29, line 2). Mr. Phillips's claim that the company's testimony was "erroneous and misleading" on this point is unsupported.

**Q. Mr. Phillips claims that the updated nominal revenue requirement analysis shows that the NPV savings over the first 20 years is lower than in the company's original analysis (Phillips Corrected Supp. Response, page 29, line 3 to page 30, line 8). How do you respond?**

A. It is not surprising that the updated nominal revenue requirement analysis, reflecting winning bids from the 2017R RFP and changes in federal tax law, produces a different net-benefit profile than what was shown in my original analysis, which reflected proxy wind resources and higher federal tax rates for corporations. Importantly, and as stated in my second supplemental direct testimony, with reduced costs from the winning bids from the 2017R RFP, the Combined Projects generate substantial near-term benefits despite a reduction in PTC benefits associated with changes in federal tax law and generate net benefits in 23 years out of the 30 years that the proposed owned-wind resources are assumed to operate (Link Second Supp., page 19, lines 6–11).

**Q. Mr. Phillips also claims that the updated nominal revenue requirement analysis shows that the majority of the customer benefits occur later and therefore the Combined Projects are now riskier as compared to the original filing (Phillips, Corrected Supp. Response, page 30, lines 10–12). Is this a fair metric for measuring risk?**

A. No. As noted above, Mr. Phillips is simply stating that updated nominal revenue-requirement analysis produces a different net-benefit profile than what was shown in my original analysis, which primarily reflects changes in Wind Project costs and associated network upgrades, federal income tax rates applicable to corporations, and updated system assumptions (*i.e.*, more current price-policy scenario assumptions and an updated load forecast). This does not mean that project risks have increased. In fact, project risks have been materially reduced since the company's original filing. For instance, when the company made its initial filing, it was uncertain whether federal tax-reform legislation would be introduced and how that legislation might impact PTC benefits, which are critical to the economic benefits of the Combined Projects. Similarly, at that time, the company had not yet issued the 2017R RFP and had not received firm pricing for wind resource bids solicited through a competitive bidding process. At this time, these uncertainties have been eliminated and replaced with known tax law changes and firm, competitive wind resource pricing, and the updated economic analysis of the Combined Projects continues to demonstrate that these investments will generate substantial customer benefits.

**Q. Mr. Phillips claims that the only way the company can claim a $167 million customer benefit using its nominal revenue-requirement analysis is to include a terminal value benefit in 2050 that was not included in the original analysis (Phillips Corrected Supp. Response, page 31, line 9 to page 32, line 6). How do you respond?**

A. It is reasonable to include a terminal value benefit for projects where the company retains control of the site at the end of the asset life and, contrary to Mr. Phillips's claim, the company's analysis does not rely heavily on 2050 results to demonstrate a positive net benefit. Even if the terminal value were completely eliminated, which would not be appropriate, the Combined Projects would still produce $124 million in net customer benefits before accounting for the conservative extrapolation methodology used by the company, conservative $CO_2$ emissions cost savings, potential upside in O&M cost savings, and upside from renewable energy credit ("REC") potential revenue.

**Q. Why did the company include a terminal value benefit for utility-owned resources?**

A. The terminal value benefit recognizes the fact that at end of a utility-owned resource's life, there is residual value that accrues to customers. For a PPA, the terminal value accrues to the project owner, not customers. That terminal value includes the facilities supporting the resources, like transmission facilities, that have longer useful lives and, in the case of generation tied to natural resources such as wind resources, there is inherent value in the site itself—particularly resources located in high-capacity-factor geographic areas like eastern Wyoming. These high-value, renewable-resource locations are often scarce or unique in their suitability for generation permitting and construction, as well as proximity to transmission.

**Q. Did the IEs comment on the inclusion of the terminal value benefit in the 2017R RFP modeling?**

A. Yes. The Utah IE observed that the terminal value is typically equal to the net salvage value of the resource, but for wind resources there are additional "assets associated with the wind site, such as land, site characteristics and generation interconnection and transmission facilities" that may provide additional value. (Utah IE Report at 33). The IE explained that the terminal value benefits reflected the depreciated value of assets that have not fully depreciated at the end of the assumed 30-year life for the wind facilities, such as transmission assets, and the appreciated value of other elements of the project that remain at the end of the 30-year life, such as development rights.

The Oregon IE also noted that the terminal value was included to account for the fact that the company would own the site at the end of the project's useful life. (Oregon IE Report at 15).

**Q. Did the IEs comment on the size of the terminal value benefit?**

A. Yes. The Utah IE noted that the terminal value was "relatively low." (Utah IE Report at 42). Likewise, the Oregon IE found that the "terminal value adders were fairly small." (Oregon IE Report at 17).

**Q. Mr. Phillips questions the terminal value calculations included in the company's analysis, claiming this benefit is speculative (Phillips Corrected Supp. Response, page 34, line 1). How do you respond?**

A. I disagree. Notably, as described above, both IE's confirmed and validated the company's bid-selection and evaluation process, and proposed no adjustment.

**Q. Mr. Phillips argues that the Combined Projects are higher risk now, compared to the original filing, because of the changes in the federal corporate tax rate, lower load forecasts, and low natural-gas prices (Phillips Corrected Supp. Response, page 33, lines 3–14). How do you respond?**

A. I disagree. It is true that each of the factors identified by Mr. Phillips decreased the customer benefits. But the decrease associated with these factors was more than offset by other factors, such as lower installed capacity costs associated with the Wind Projects. In total, when all of the changes are considered, the company's analysis shows that risks have decreased and customer benefits have increased since the initial filing.

**Q. Mr. Phillips claims that the company has not assessed the risk associated with wind variability (Phillips Corrected Supp. Response, page 35, line 2 to page 36, line 6). Is this true?**

A. No. PacifiCorp performed robust risk analysis of wind variability, including the retention of a third-party expert to verify the wind-production estimates for every bid selected to the initial shortlist in the 2017R RFP. Mr. Chad A. Teply also provided testimony explaining that the company's existing wind projects in the Medicine Bow area of Wyoming have out-performed pre-construction estimates (Teply Rebuttal, page 15, line 28 to page 16, line 8).

**Q. Mr. Phillips claims that there is a risk that future qualifying facility ("QF") development may cause curtailment of the Wind Projects, thereby reducing their production (Phillips Corrected Supp. Response, page 36, line 7 to page 37, line 2). Is this a reasonable concern?**

A. No. Mr. Phillips describes curtailment risk associated with a 320 megawatt ("MW") QF project in eastern Wyoming that has an executed interconnection agreement. This interconnection agreement requires additional transmission upgrades, which includes all of Energy Gateway West and Energy Gateway South, scheduled to occur in 2024. Mr. Phillips then correctly explains that the company did not reserve interconnection capacity for this QF project when performing its economic analysis of the Combined Projects.

PacifiCorp did not reserve any of the incremental interconnection capability associated with the Aeolus-to-Bridger/Anticline transmission line for this particular 320 MW QF project referenced by Mr. Phillips because the project can only interconnect if the transmission upgrades identified in this QF project's executed interconnection agreement are built, including all of Energy Gateway West and Energy Gateway South. The upgrades are required for this 320 MW QF project to proceed, would increase interconnection capacity in the region, and would increase the transfer capability out of eastern Wyoming. Consequently, if this QF project moves forward, it would mean that all of Energy Gateway West and Energy Gateway South have been built, which would mitigate, not increase, any potential curtailment of the proposed Wind Projects.

**Q. Mr. Phillips is concerned that the company has not thoroughly evaluated the Combined Projects (Phillips Corrected Supp. Response, page 5, lines 15–16) and faults the company for not conducting any capital cost over-run or load forecast sensitivities in its updated analysis (Phillips Corrected Supp. Response, page 38, lines 1–6). How do you respond?**

A. The company's economic analysis in this docket has been thorough and extensive. The updated economic analysis summarized in my second supplemental direct testimony alone includes 26 SO model simulations and 26 PaR simulations. Each PaR simulation considers 50 different iterations of system performance with variations in stochastic variables, which includes variations in load. Accounting for the stochastic system simulations performed using PaR, the economic analysis summarized in my second supplemental direct testimony represents over 1,300 simulations of PacifiCorp's system over a 20-year forecast time frame. Through these studies, the company has assessed how the net benefits of the Combined Projects are affected by the proposed wind repowering project, solar resource opportunities, selection of alternative wind-turbine equipment, alternative natural-gas price assumptions, alternative $CO_2$ price assumptions, and application of alternative assumptions for O&M cost and REC revenues.

It is also important to recognize that the winning bids selected to the 2017R RFP final shortlist are based on firm-pricing proposals through a competitive solicitation process with oversight from two IEs. The company also provided evidence that its prior two large-scale transmission projects were 19 percent and six percent under budget (Vail Rebuttal, page 15, Table 1).

**Q. Are all of the risks identified by Mr. Phillips asymmetrical, *i.e.*, can the risks only run against customer interests?**

A. No. Variability of the factors described by Mr. Phillips can favor customers too. Project performance can be better than expected, as Mr. Teply indicates has occurred. Capital costs can be lower than expected, as Mr. Vail indicates has occurred. And ongoing O&M costs can be less than expected, as I previously discussed.

**Q. Is there also a risk that natural-gas prices will be higher than expected?**

A. Yes. In my direct testimony, I noted that the low natural-gas price forecast assumed stagnant liquefied natural gas ("LNG") exports (Link Direct, page 32, lines 13–16). According to the U.S. Energy Information Administration's *Annual Energy Outlook 2018* ("AEO 2018"), published on February 6, 2018, the United States is now a net exporter of natural gas and its reference case shows increased LNG exports in the coming years as additional terminals come into service. The increased exports will likely put pressure on future natural gas prices, meaning that over the next 32 years (*i.e.*, until 2050), it is unlikely that natural gas prices will remain as low as the low case used here.

**Q. Has WIEC previously acknowledged price risk?**

A. Yes. In the context of avoided-cost pricing, WIEC argued that "there is price risk associated with the acquisition of any long-term resource," but recognized that "fixed-price risk operates in both directions."[3] Thus, WIEC concluded: "If the Company's

[3] *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. 20000-481-EA-15 (Record No. 14220), Direct Testimony of Kevin C. Higgins on behalf of the Rocky Mountain Coalition for Renewable Energy, the Wyoming Industrial Energy Consumers, and Chevron Power and Energy Management Company at page 10, lines 19–21 (Jan. 4, 2016).

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."[4]

Moreover, WIEC argued that the risk that future energy prices would be higher was greater than the risk future prices would be lower: "the 'downside risk' of higher future prices is essentially limitless, while the realistic 'upside risk' of lower future prices is relatively limited.[5] The same is true here—there is no bias in the medium natural-gas price forecast and therefore, according to WIEC's reasoning, actual future natural-gas prices are as likely to be higher as they are lower.

**Q. Does Mr. Phillips continue to rely on the low natural-gas price scenario?**

A. Yes. Mr. Phillips reiterated that the low natural-gas price forecast is the "status quo" and appears to continue to rely heavily on the low natural-gas price scenarios for his analysis. (Phillips Corrected Supp. Response, page 17, lines 18–19). But, in prior testimony on avoided-cost pricing, WIEC urged the Commission to use the company's official forward price curve, which corresponds to the medium natural-gas price forecast, for setting long-term avoided cost prices, as noted above.

In addition, WIEC witness Kevin C. Higgins previously recommended that the Oregon Commission rely on the company's official forward price curve when setting stranded-cost payments.[6]

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[4] *Id.* at page 10, line 21 to page 11, line 1.

[5] *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. 20000-481-EA-15 (Record No. 14220), Joint Post-Trial Brief of the Rocky Mountain Coalition for Renewable Energy, the Wyoming Industrial Energy Consumers, Chevron Power and Energy Management Company, and EverPower Wind Holdings, Inc. at 5 (Apr. 19, 2016).

[6] *In the Matter of PacifiCorp, dba Pacific Power 2014 Transition Adjustment Mechanism*, OPUC Docket No. UE 264, Reply Testimony of Kevin C. Higgins on behalf of Noble Americas Energy Solutions LLC at 22, lines 13–15 (June 4, 2013) ("I recommend that projected market prices be calculated directly based on the utility's forward price curve used for projecting its net power costs").

**Q. Do any other parties provide testimony related to the company's economic analysis?**

A. Yes. Mr. Freeman testifies that he has no reason to doubt the veracity of the company's analysis because it is "essentially an extension of the Company's Integrated Resource Planning (IRP) analysis," which "is a robust and exhaustive process with ample opportunity for input from interested stakeholders." (Freeman, Supp. Direct, page 9, line 6 to page 10, line 4). Based on his review of the company's analysis, Mr. Freeman concludes that, "it is more likely, on balance, that customers will benefit rather than be harmed." (Freeman Supp. Direct, page 10, lines 11–12).

## SOLAR RESOURCE SENSITIVITY

**Q. Please summarize the solar resource sensitivity provided in your previous testimony.**

A. My second supplemental direct testimony provided robust modeling results through 2036 using the SO model and PaR based on preliminary bid analysis from the 2017S RFP (Link Second Supp. Direct, page 20, line 5 to page 24, line 3). Those modeling results supported two important conclusions.

First, the solar PPAs provided fewer benefits than the Combined Projects under the medium natural gas, medium $CO_2$ scenario, and slightly fewer benefits under the low natural gas, zero $CO_2$ scenario using PaR and slightly more benefits under the low natural gas, zero $CO_2$ scenario using the SO model. In other words, under the medium natural gas, medium $CO_2$ scenario, the Combined Projects are superior, and under the low natural gas, zero $CO_2$ scenario the Combined Projects are roughly equal to the solar PPAs.

Second, when analyzed together, the Combined Projects and solar PPAs produced greater customer benefits under both the medium natural gas, medium $CO_2$ scenario and low natural gas, zero $CO_2$ scenario.

These conclusions indicated that it is not a question of whether the company should pursue the Combined Project *or* the solar PPAs, but rather a question of whether the company should pursue the Combined Projects *and* the solar PPAs.

**Q. Did the company provide the solar sensitivity to the IEs that monitored the 2017R RFP?**

A. Yes. The Oregon IE noted in his report: "In all cases the combination of solar and shortlisted [wind] resources provided more net benefits." (Oregon IE Report at 36). Although the Utah IE did not specifically comment on the solar sensitivity, he did not challenge it in his final report (*see* Utah IE Report at 61).

**Q. Mr. Phillips argues that the solar PPAs represent a superior resource option for customers and therefore the Combined Projects are contrary to the public interest (Phillips Corrected Supp. Response, page 17, lines 8–14). Do you agree?**

A. No. PacifiCorp has now completed its bid-evaluation and selection process for the 2017S RFP, and the complete analysis and results confirm the company's earlier assessment that the solar resources do not displace the economic benefits of the Combined Project. While the base economic analyses of solar PPA bids show that there are potential customer benefits associated with a 1,320 MW portfolio of solar PPAs from the 2017S RFP, subsequent sensitivity analyses show a risk, unique to solar resource opportunities, that the projected benefits for the solar PPAs are overstated, as I will discuss below.

In addition, driven by uncertainties regarding tariff and tax reforms, current solar resource pricing likely reflects a risk premium, and solar project costs are expected to decline. Because the 30-percent ITC is available for solar resources that come online by 2021, PacifiCorp expects that solar pricing received in late 2019 for projects that could come online in 2021 will be lower than pricing received in the 2017S RFP and would avoid the current risk premium associated with the tariff and tax reform uncertainties. Thus, PacifiCorp does not need to act now and has decided not to select any of the 2017S RFP bids to the final shortlist.

PacifiCorp will continue to assess potential economic benefits from solar resource opportunities in the 2019 IRP, including a thorough evaluation of hourly price-profile and capacity-contribution risks (discussed below) with full stakeholder engagement and a more orderly assessment of the potential customer benefits of solar generation. Should subsequent analysis in the 2019 IRP demonstrate that solar resource opportunities provide economic benefits for customers, there will be sufficient time to initiate a new competitive solicitation process for projects capable of achieving commercial operation by the end of 2021 that can qualify for the 30-percent ITC. This potential solicitation could consider storage bids as a means to mitigate valuation risks and allow sufficient time for participants to be further along in the transmission interconnection process.

**Q. Did PacifiCorp inform the IE overseeing the 2017S RFP of its final shortlist results?**

A. Yes. PacifiCorp summarized its 2017S RFP final shortlist bid evaluation and selection analysis with London Economics International, LLC, the IE retained by the company to monitor the 2017S RFP, on March 12, 2018. This summary is included as Confidential Exhibit RMP__(RTL-2SR).

**Q. What additional sensitivity analyses did PacifiCorp perform in the 2017S RFP to better assess the potential customer benefits and valuation risks associated with the solar resource bids?**

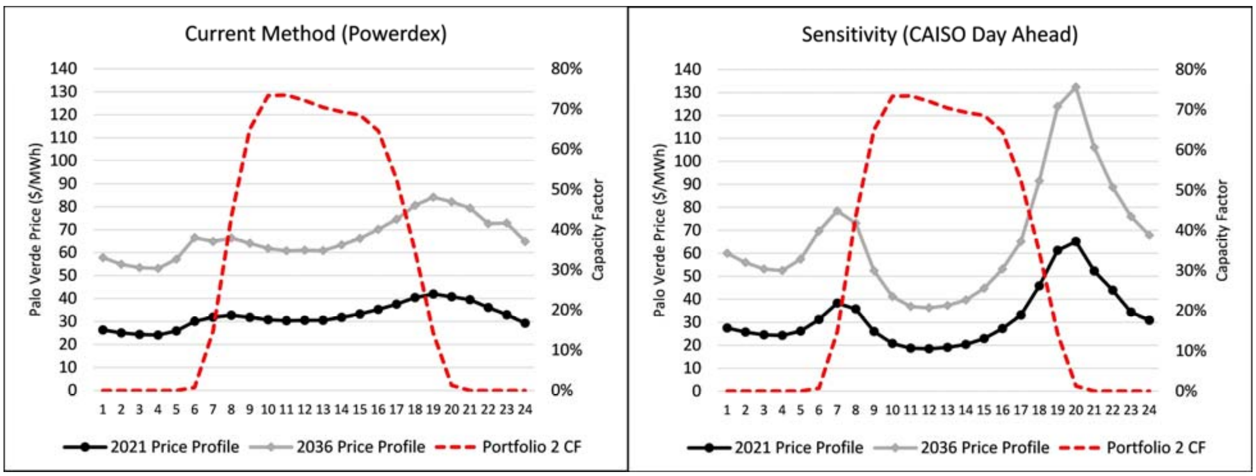
A. PacifiCorp performed two additional sensitivities. First, the company refined how it converts its forward market prices into hourly prices to more accurately reflect hourly market-price variation in those hours when solar resources are producing energy. Second, the company performed a capacity-contribution sensitivity to assess how changes in the assumed ability of solar resource to meet peak load during periods when there is an increased probability of loss-of-load events affect the overall customer benefits.

**Q. Please describe the hourly price-profile sensitivity developed to analyze bids in the 2017S RFP.**

A. PacifiCorp uses hourly price scalars, which are applied to monthly on-peak and off-peak prices in the forward price curve, to derive hourly market price profiles that vary by month and day type (*i.e.*, weekdays, Saturdays, and Sundays/holidays). PacifiCorp currently uses five years of hourly Powerdex price data to develop price scalars. The company's review of the Powerdex data shows that the five-year price history is not supported by a significant volume of reported transactions (many hours have no market pricing inputs) and that the resulting hourly price shapes do not align with price observed in operations that are being increasingly influenced by growth in solar resources across the region. Thus, for the hourly price-profile sensitivity, PacifiCorp developed an alternative set of price scalars that are derived from one year of day-ahead hourly prices available from the California Independent System Operator ("CAISO").

The figure below illustrates the differences between the Powerdex-derived scalars and the CAISO-derived scalars.

**Figure 1-SR: Hourly Price-Scenario Sensitivity**




The figure at top left shows representative average hourly price profiles as derived from historical Powerdex data and used in the bid-evaluation process of the 2017S RFP. The figure at top right shows representative average hourly price profiles derived from historical CAISO data and used in this sensitivity. In both figures, the hourly price profile is based on the average hourly prices from representative months (January, April, July, and October) and shown alongside the average hourly capacity profile of bids included in a solar PPA bid portfolio. The sensitivity shows that when accounting for the growth in solar resources across the region, prices are lower during those hours when the resources in the solar PPA bid portfolio are expected to generate electricity.

**Q. Does the company intend to use the CAISO-derived scalars in future resource analyses?**

A. Yes. The company intends to use the refined scalars in the 2017 IRP Update and future IRPs.

**Q. How does the refined hourly price scalars impact the benefits of the solar PPA resources?**

A. The use of the CAISO-derived hourly price scalars decreased the benefits of the solar PPAs. This outcome was observed regardless of whether these price scalars were applied to studies evaluating solar PPA bids with or without the Combined Projects. When analyzed in isolation from the Combined Projects, 20-year PaR studies (through 2036) show that application of the CAISO-derived hourly price scalars decreased solar PPA benefits from $174 million to $108 million (a reduction of $66 million) based on stochastic-mean PaR results and from $183 million to $114 million (a reduction of $69 million) based on risk-adjusted PaR results in the medium natural gas, medium $CO_2$ price-policy scenario.

When analyzed under the low natural gas, zero $CO_2$ price-policy scenario, the CAISO-derived hourly price scalars decreased the benefit of the solar PPAs from showing a $45 million net benefit to showing a $10 million net cost (a $55 million reduction in benefits) based on stochastic-mean PaR results and from showing a $48 million net benefit to showing a $10 million net cost (a $58 million reduction in benefits) based on risk-adjusted PaR results.

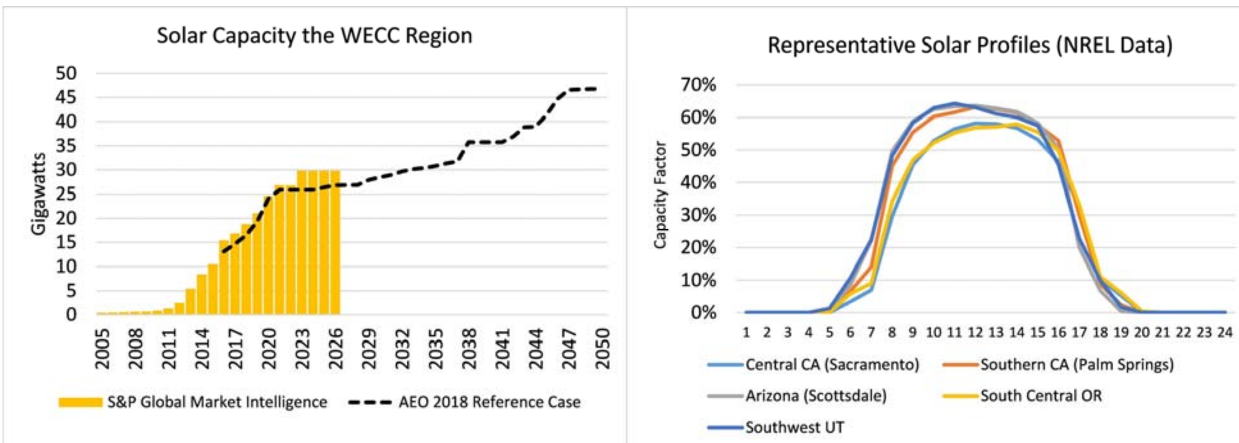
The price-policy scenario assumptions used to analyze solar PPA bids in the 2017S RFP are identical to those used to analyze the Combined Projects in my second supplemental direct testimony, with the exception that the medium $CO_2$ price assumptions were correctly applied as a nominal cost instead of real costs in 2012 dollars.

**Q. Are there any other issues to consider related to the price-profile used to evaluate the solar PPA bids?**

A. Yes. The expected increase in solar generation, coupled with correlation among expected solar resource generation profiles across the west, has had a significant impact on hourly prices and will continued to do so as development increases. S&P Global Market Intelligence tracks power-plant capacity, and reports that solar capacity in the Western Electricity Coordinating Council ("WECC") region, which represents capacity that is online or announced to go online having obtained regulatory approvals, will grow from 16.8 gigawatts ("GW") in 2017 to 29.8 GW by 2023 (growth of approximately 77 percent over six years). Similarly, AEO 2018 Reference Case trends closely with the S&P Global Market Intelligence data, and shows continued growth of solar capacity in the WECC, which reaches 46.8 GW by 2050. By the end of a 25-year solar PPA (2045), the AEO 2018 Reference Case predicts that solar capacity in the WECC region will grow to 41.3 GW, which is 2.5 times the amount of solar capacity reported for 2017.

The rapid increase in solar capacity across the region over the past five years has significantly impacted hourly market prices, and continued growth in new solar capacity could further affect the market value of solar energy beyond what has been analyzed in the price-profile sensitivity described above. Moreover, proxy solar profiles from the National Renewable Energy Laboratory ("NREL") show a high degree of correlation among potential solar sites across the WECC region, indicating that the potential impacts on hourly price profiles are likely regardless of where new solar is added. The figure below illustrates the expected growth in solar generation and the correlated generation profiles throughout the region.

**Figure 2-SR: Growth in Solar Generation and Correlation of Generation Profiles**

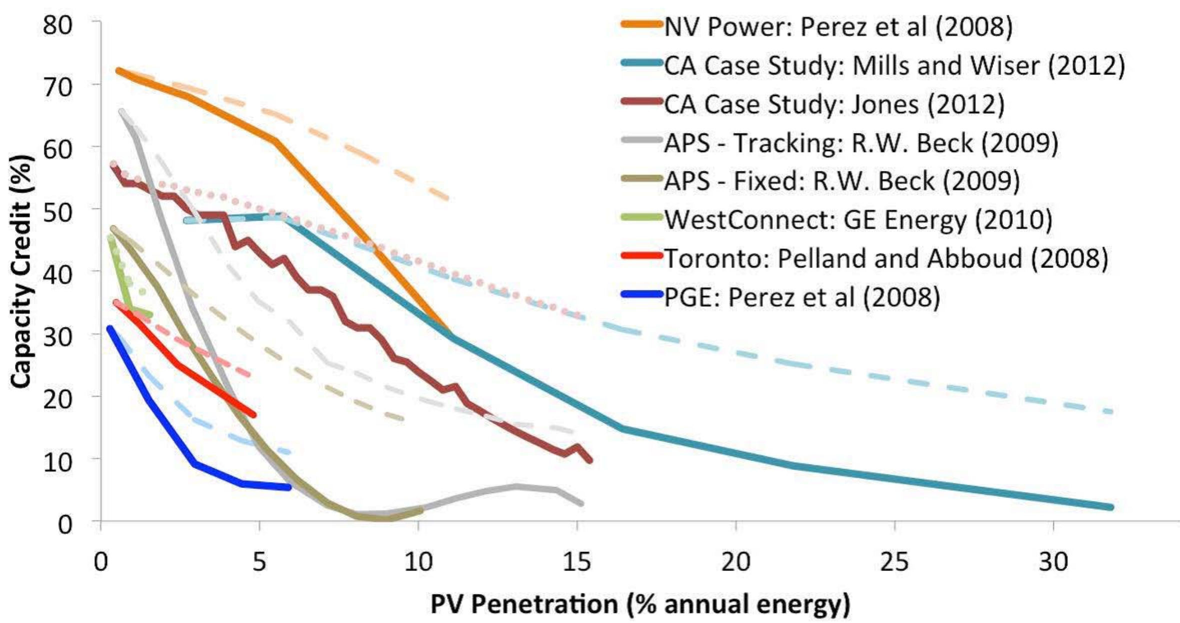



**Q. Please describe the capacity-contribution sensitivity used in the 2017S RFP bid evaluation and selection process.**

A. The capacity-contribution sensitivity is designed to assess the risks associated with overstating the capacity contribution of solar resources when evaluating the potential customer benefits of solar PPA bids. The capacity contribution of solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. The company’s base economic analysis used to establish the 2017S RFP and used to support the solar sensitivity studies in my supplemental direct and second supplemental direct testimony applied the capacity contribution values for solar resources developed for the 2017 IRP (59.7 percent for the solar PPAs, which are all located in Utah), and therefore, the base economic analysis assumes that the 1,320 MW of solar PPA capacity includes in the 2017S RFP bid portfolio can displace the need for approximately 788 MW of system capacity (59.7 percent multiplied by the 1,320 MW of solar PPA capacity).

As more highly correlated solar generation is added to the system, the energy output from these resources is more likely to shift the timing of potential loss-of-load events to evening hours when solar irradiance is low and generation levels are greatly reduced or zero. Consequently, solar capacity-contribution values are highly sensitive to increasing solar penetration levels. The figure below illustrates study results concluding that additional solar generation reduces the capacity contribution of solar resources.

**Figure 3-SR: Capacity Contribution Compared to Penetration**




Source: Mills, Andrew, and Ryan Wiser. 2012. "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes." LBNL-5933E, Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory.

For PacifiCorp, the addition of 1,320 MW of solar capacity would more than double the amount of solar resources on its system. The capacity-contribution sensitivity evaluates the economic impact of halving the capacity-contribution value from 59.7

percent to 29.9 percent when applying medium natural gas, medium $CO_2$ and low natural gas, zero $CO_2$ price-policy assumptions. Considering that the company will begin using the hourly price profiles derived from day-ahead CAISO data in the 2017 IRP Update, the capacity-contribution sensitivity also includes the CAISO-derived hourly price profile.

**Q. What were the results of this capacity-contribution sensitivity used to evaluate bids in the 2017S RFP?**

A. With the capacity-contribution assumption reduced from 59.7 percent down to 29.9 percent, the amount of system capacity that the 1,320 MW of solar resource capacity can displace is reduced from 788 MW to 394 MW. This reduces the resource-deferral value of the solar PPA resources, which in turn reduces the net benefits of the solar PPA bids.

The combined effect of the hourly price-profile and capacity-contribution assumptions, when solar PPA bids are analyzed in isolation of the Combined Projects over a 20-year time frame in PaR, is to decrease the solar PPA benefits from \$174 million to \$69 million (a reduction of \$105 million in benefits) based on stochastic-mean PaR results, and from \$183 million to \$73 million (a reduction of \$110 million in benefits) based on risk-adjusted PaR results in the medium natural gas, medium $CO_2$ price-policy scenario.

When analyzed under the low natural gas, zero $CO_2$ price-policy scenario, the combined effect of the hourly price-profile and capacity-contribution assumptions is to decrease the benefit of the solar PPAs from showing a \$45 million net benefit to showing a \$56 million net cost (a \$101 million reduction in benefits) based on stochastic-mean PaR results, and from showing a $48 million net benefit to showing a $58 million net cost (a $106 million reduction in benefits) based on risk-adjusted PaR results.

Again, the price-policy scenario assumptions used to analyze solar PPA bids in the 2017S RFP are identical to those used to analyze the Combined Projects in my second supplemental direct testimony, with the exception that the medium $CO_2$ price assumptions were correctly applied as a nominal cost instead of real costs in 2012 dollars.

**Q. When assessing the impact of the hourly price-profile sensitivity for the 2017S RFP, did the company consider how the CAISO-derived hourly price scalars might affect the economic analysis of the Combined Projects?**

A. Yes. The table below summarizes how the CAISO-derived hourly price-scalar assumptions impact the Combined Projects and, separately, how these assumptions impact the 1,320 MW bid portfolio that includes solar PPAs without the Combined Projects when applying medium natural gas, medium $CO_2$ price-policy assumptions.

**Table 1-SR: Solar-Only Compared to Combined Projects**
**Hourly-Price Sensitivity System Modeling Results**
**(Medium Gas, Medium $CO_2$)**

| | **Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million** | **Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million** |
|---|---|---|
| **Combined Projects** | | |
| Benchmark Analysis (Second Supplemental Direct) | $(357) | $(386) |
| Hourly Price-Profile Sensitivity & Nominal $CO_2$ | $(328) | $(343) |
| Decrease in Net Benefits | $29 | $43 |
| **2017S Solar PPA Bid Portfolio** | | |
| Benchmark Analysis (Current Hourly Scalars) | $(237) | $(248) |
| Hourly Price-Profile Sensitivity | $(160) | $(168) |
| Decrease in Net Benefits | $77 | $80 |

This analysis shows that the new hourly prices-profile decreases the customer benefits of the Combined Projects on a stand-alone basis and decreases the customer benefits of the solar PPAs on a stand-alone basis. But, importantly, the reduction in net benefits associated with the hourly-price profile sensitivity is between 1.9 and 2.7 times greater for the solar PPAs than it is for the Combined Projects when applying medium gas, medium $CO_2$ price-policy assumptions.[7] The disproportionate impact is consistent with the fact that solar generation profiles are more highly correlated with the impact solar resources are having on hourly price profiles relative to wind. While both types of technologies are faced with the same reduction in the market value of energy during the middle of the day, the wind generation produces energy during the early morning and late evening hours, when the market value of energy is higher.

**Q. Did you conduct this same analysis for the low gas, zero $CO_2$ price-policy scenario?**

A. Yes. The table below summarizes how the CAISO-derived hourly price-scalar assumptions impact the Combined Projects and the 1,320 MW solar PPA bid portfolio when applying low gas, zero $CO_2$ price-policy assumptions.

[7] When applying the hourly profiles derived from CAISO data to the Combined Project studies, the medium gas, medium $CO_2$ price-policy scenario reflects nominal application of $CO_2$ price assumptions, which were inadvertently analyzed in 2012 dollars in the original benchmark analysis. This ensures the sensitivity results for new wind and transmission can be directly compared with the solar only sensitivity results.

**Table 2-SR: Solar-Only Compared to Combined Projects**
**Hourly-Price Sensitivity System Modeling Results**
**(Low Gas, Zero $CO_2$)**

| | **Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million** | **Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million** |
|---|---|---|
| **Combined Projects** | | |
| Benchmark Analysis (Second Supplemental Direct) | ($150) | ($156) |
| Hourly Price-Profile Sensitivity | ($125) | ($130) |
| Decrease in Net Benefits | $25 | $26 |
| **2017S Solar PPA Bid Portfolio** | | |
| Benchmark Analysis (Current Hourly Scalars) | ($125) | ($131) |
| Hourly Price-Profile Sensitivity | ($69) | ($72) |
| Decrease in Net Benefits | $56 | $59 |

Similar to the medium gas, medium $CO_2$ price-policy scenario, the results show that the net benefits associated with both the Combined Projects and the solar PPAs decreased, but, again, the reduction in net benefits associated with the hourly-price profile sensitivity is approximately 2.2 to 2.3 times greater for the solar PPAs than it is for the Combined Projects when applying low gas, zero $CO_2$ price-policy assumptions.

**Q. What conclusions can you draw from these results?**

A. The solar PPAs are more sensitive to the refined hourly price-profile and therefore present a greater risk that the customer benefits of the solar PPAs are overstated relative to the Combined Projects.

**Q. Did the company apply the capacity-contribution sensitivity to the Combined Projects?**

A. No. Unlike solar resources, wind resources are expected to generate in all hours of the day, and thus the energy output from wind resources are not likely to shift the timing of potential loss-of-load events to hours when the wind is not generating. Consequently, the capacity-contribution value for wind resources (15.8 percent for east wind as reported in the 2017 IRP) is less likely to be materially impacted with increasing penetration of either new wind or solar resources.

**Q. How do the economics of the Combined Projects with CAISO-derived hourly price scalars compare to the economics of the solar PPA bid portfolio that reflects the combined effects of the alternative hourly-price and capacity-contribution assumptions?**

A. The table below summarizes how these assumptions impact the Combined Projects and the 1,320 MW solar PPA bid portfolio when applying medium natural gas, medium $CO_2$ price-policy assumptions.

**Table 3-SR: Solar-Only Compared to Combined Projects Capacity-Contribution Sensitivity System Modeling Results (Medium Gas, Medium $CO_2$)**

| | Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million | Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million |
|---|---|---|
| **Combined Projects** | | |
| Benchmark Analysis (Second Supplemental Direct) | ($357) | ($386) |
| Hourly Price-Profile Sensitivity & Nominal $CO_2$ | ($328) | ($343) |
| Decrease in Net Benefits | $29 | $43 |
| **2017S Solar PPA Bid Portfolio** | | |
| Benchmark Analysis (Current Hourly Scalars/Cap Cont.) | ($237) | ($248) |
| Hourly Price-Profile/Cap Cont. Sensitivity | ($93) | ($97) |
| Decrease in Net Benefits | $144 | $151 |

As set forth above, the combined effect of the hourly price-profile and capacity-contribution assumptions is to reduce the net benefits of the solar PPA bids by between $144 million and $151 million in the medium gas, medium $CO_2$ price-policy scenario, which is approximately 3.5 to 5.0 times greater than the impact of the hourly price-profile on the Combined Projects.

**Q. What do these sensitivities show when applying low gas, zero $CO_2$ price-policy assumptions?**

The table below summarizes how hourly price-scalar and capacity-contribution sensitivity assumptions affect the Combined Projects and the 1,320 MW solar PPA bid portfolio when applying low natural gas, zero $CO_2$ price-policy assumptions.

**Table 4-SR: Solar-Only Compared to Combined Projects Capacity-Contribution Sensitivity System Modeling Results (Low Gas, Zero $CO_2$)**

| | Stochastic-Mean PaR PVRR(d) (Benefit)/Cost $ million | Risk-Adjusted PaR PVRR(d) (Benefit)/Cost $ million |
|---|---|---|
| **Combined Projects** | | |
| Benchmark Analysis (Second Supplemental Direct) | ($150) | ($156) |
| Hourly Price-Profile Sensitivity | ($125) | ($130) |
| Decrease in Net Benefits | $25 | $26 |
| **2017S Solar PPA Bid Portfolio** | | |
| Benchmark Analysis (Current Hourly Scalars/Cap Cont.) | ($125) | ($131) |
| Hourly Price-Profile/Cap Cont. Sensitivity | ($8) | ($8) |
| Decrease in Net Benefits | $117 | $123 |

The combined effect of the hourly price-profile and capacity-contribution assumptions is to reduce the net benefits of the solar PPA bids by between $117 million and $123 million in the low natural gas, zero $CO_2$ price-policy scenario, which is approximately 4.7 times greater than the impact of the hourly price-profile on the Combined Projects.

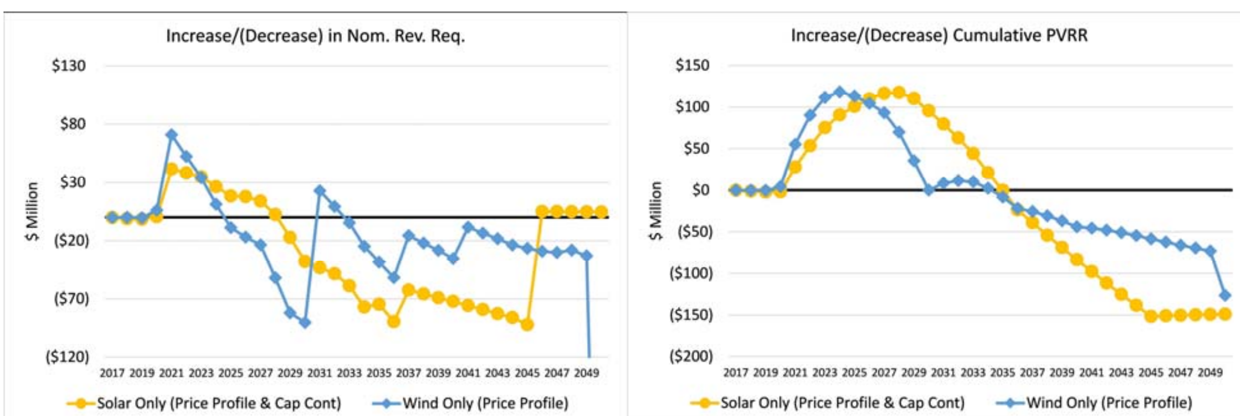
**Q. What conclusions can you draw from these sensitivities?**

A. The sensitivities set forth above demonstrate that there is risk that the customer benefits from the solar PPAs are overstated because the assumed capacity-contribution value and associated resource-deferral benefits are likely to be lower than what is assumed in the base analysis. Importantly, this same risk does not apply to the Combined Projects. In fact, the Combined Projects will bring additional transmission capacity and a diverse resource that is uncorrelated to solar production (*i.e.*, wind production occurs in all hours, not just daylight hours). Moreover, solar-resource opportunities do not displace the benefits of the Combined Projects, and similarly, the Combined Projects do not displace the potential benefits of solar-resource opportunities. Solar resources are best viewed as an incremental opportunity to the Combined Projects, not as an alternative.

**Q. Did the company perform an annual revenue requirement analysis to assess how these risks affect the Combined Projects and the 1,320 MW solar PPA bid portfolio?**

A. Yes. Figure 4-SR provides these annual revenue requirement results when applying medium natural gas, medium $CO_2$ price-policy assumptions. The figure also shows the cumulative PVRR, where the PVRR for each year represents the present value of annual revenue requirement from that year and all prior years.

**Figure 4-SR: Annual Revenue Requirement Results**

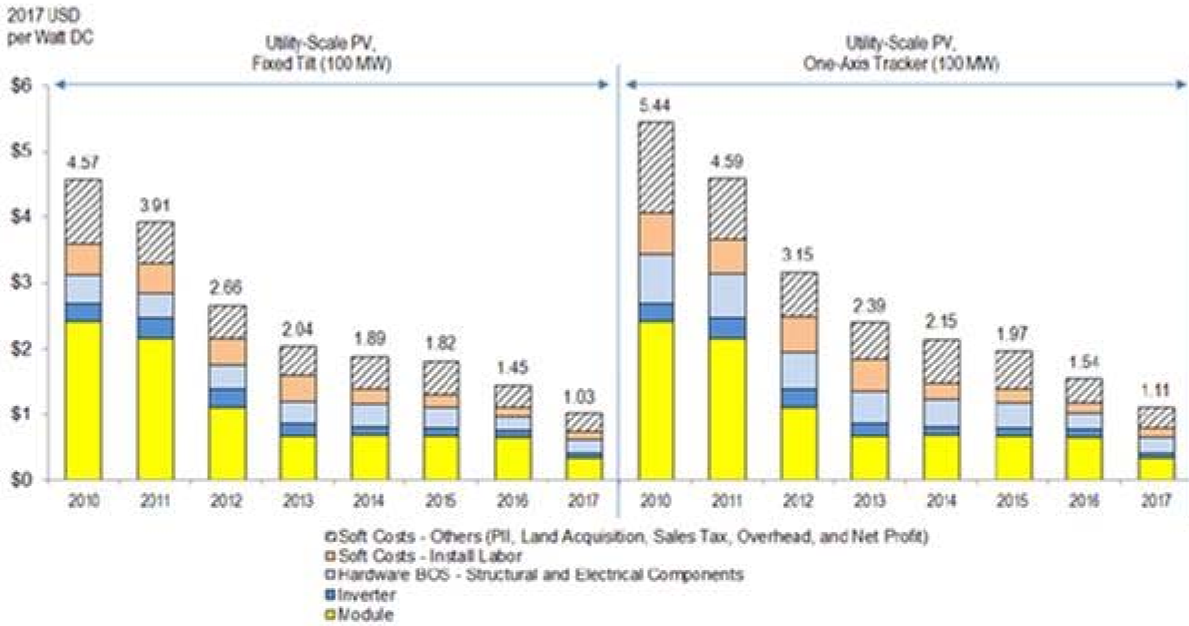



As Figure 4-SR illustrates, the PVRR(d) benefits of the Combined Projects, reflecting an hourly price profile derived from the CAISO day-ahead data, when calculated from nominal revenue requirement results is $127 million. The PVRR(d) benefits of the solar PPAs, reflecting an hourly price profile derived from the CAISO day-ahead data and reflecting a 29.9 percent capacity-contribution value, is $149 million. The Combined Projects have a higher net cost relative to the solar PPAs for two years; however, with PTCs, the net costs drop below the solar PPA bids beginning year three and the Combined Projects begin producing net benefits by 2025. The solar PPAs do not begin producing net benefits until 2029. Beyond the first few years, the cumulative PVRR of the Combined Projects is favorable relative to the solar PPA bids through 2035. Over the long term, more speculative benefits that reflect no further deterioration to hourly price profiles or capacity-contribution value drive the cumulative PVRR benefits of the solar PPA bids below wind. In 2050, the terminal value assumed for owned assets (applicable to 1,011 MW of the new wind) improves the cumulative PVRR for the Combined Projects.

**Q. In addition to the risk associated with hourly prices and capacity contribution, are there any other risks associated with obtaining solar PPAs now as a result of the 2017S RFP?**

A. Yes. As shown in Figure 5-SR, solar resource costs have been steadily declining and the trend is expected to continue.

**Figure 5-SR: Solar Resource Costs**




Source: Fu, Ran, David Feldman, Robert Margolis Mike Woodhouse, and Kristen Ardani. "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017." *National Renewable Energy Laboratory*. September 2017.

As illustrated above, solar resource costs have fallen over time with a 77-percent reduction in utility-scale solar photovoltaic system costs for fixed-tilt systems over the 2010-2017 time frame and an 80-percent reduction for single-axis tracker systems. Stemming from increases in module costs due to a global shortage of Tier 1 module supply, tax-reform uncertainty, and tariff uncertainty, solar costs increased for the first time in the third quarter of 2017 since the Solar Energy Industry Association and GTM Research began publishing market cost reports in 2010; however, cost reductions are expected to continue over the long term. By the second half of 2019, tariff and tax risks, including implications on tax-equity markets, are expected to have been mitigated and module costs are expected to fall to as low as

30 cents-per-watt on a direct-current basis by 2019.[8] Additional reductions to the cost of inverters, tracking structures, and other balance-of-system components are expected to further reduce total-system costs in 2019 and 2020.

**Q. How do these changes in solar resource costs impact the company's assessment of the 2017S RFP resources?**

A. When considering the relatively long lead time between contract execution of 2017S RFP solar resource bids with commercial operation dates in late 2020, and the fact that the 30-percent ITC is available for solar projects coming online as late as 2021, current pricing for solar resources likely reflects a risk premium, by both bidders and their tax-equity investors, related to tariff and tax-reform uncertainties. Solar pricing received in late 2019 for projects that could come online in 2021 and qualify for the 30-percent ITC should reflect expected cost reductions and avoid the current risk premium associated with tariff and tax-reform uncertainties.

**Q. Mr. Phillips claims that the company was misleading because it did not present the nominal revenue requirement results through 2050 for the solar sensitivity presented in the second supplemental direct testimony (Phillips Corrected Supp. Response, page 16, line 5 to page 17, line 4). How do you respond?**

A. I disagree that the company's testimony and analysis was misleading. As I described in my second supplemental testimony, the company's system-modeling analysis demonstrated that the combined benefits of the solar resources and the Combined Projects were higher than the individual benefits of each resource option alone. Mr. Phillips does not dispute that conclusion.

[8] "Why Solar Is on a Path to Dominance," *Greentech Media,* Yuri Horwitz, February 15, 2018 (available at https://www.greentechmedia.com/articles/read/solar-is-going-to-win-bigly).

As I discussed earlier, the system-modeling results provide a view of the economic analysis that is consistent with the planning period and approach used to identify a least-cost, least-risk preferred portfolio in the IRP. While the nominal revenue-requirement analysis provides a sense of how the Combined Projects and solar resources might impact customer rates over time, longer-term results in this analysis are increasingly difficult to project. The company focused on the system-modeling results when performing its solar resource sensitivities because these studies are more suitable for comparing different resource portfolios, consistent with how resource portfolios are evaluated in the IRP.

**Q. Mr. Phillips claims that the nominal revenue-requirement results provided in the company's workpapers supporting its second supplemental direct testimony show that solar PPAs are a superior resource option when compared to the Combined Projects (Phillips Corrected Supp. Response, page 17, lines 5–14). How do you respond?**

A. First, as noted above, Mr. Phillips does not dispute that the customer benefits of the Combined Projects and the solar resources together are higher than each resource option alone when analyzed over a 20-year time frame, consistent with evaluation of resource portfolios in the IRP. That is the key finding reported in my solar sensitivity analysis.

Second, as described above, there is a risk that benefits of the solar PPAs reported in my second supplemental testimony are overstated, as demonstrated by the additional sensitivities discussed above, and that these risks could increase over time.

**Q. Mr. Phillips claims that the solar option is also less risky than the Combined Projects because the solar resources are PPAs (Phillips Corrected Supp. Response, page 18, lines 3–13 and page 21, line 11 to page 22, line 4). Is this true?**

A. No. Mr. Phillips's focus on only the commercial structure is overly simplistic. As described above, solar resources generally present additional risks that do not apply to wind resources. Specifically, solar resources tend to generate most during the day, when demand and prices are low. Because the generation profile of solar resources is consistent across the west, the increasing penetration of solar resources throughout the region will likely further depress prices during the period when solar generates. Thus, there is a risk with solar that the value of the generation provided will be less than current forecasts and could be less than projected in the hourly price-profile sensitivities.

Moreover, the capacity contribution of solar resources is likely decreasing as solar penetration increases. As discussed above, this is a risk that is unique to solar resources and means that the customer benefits for solar resources are likely overstated.

**Q. Are there any other risks associated with pursuing solar resources now?**

A. Yes. Mr. Phillips also claims that the solar PPAs are less risky because they do not require the Aeolus-to-Bridger/Anticline transmission line. But, as described by Mr. Vail, that transmission line will provide substantial customer benefits independent of the fact that it will enable interconnection of the Wind Projects. And, as described by Mr. Vail, the company currently anticipates construction of the line by 2024 even without the Combined Projects. Thus, far from reducing customer risk, if the company selected the solar PPAs instead of the Combined Projects, it would create a very real risk that customers would ultimately bear the cost of the Aeolus-to-Bridger/Anticline line without the subsidy provided by the PTC-eligible Wind Projects. And if the costs to construct the Aeolus-to-Bridger/Anticline line are considered in the solar PPA analysis, with the addition of PTC-eligible wind resources, the benefits of those solar PPA resources would decrease dramatically and would be substantially less than the benefits of the Combined Projects.

**Q. Mr. Phillips also argues that the solar PPAs are superior because they provide no equity returns to PacifiCorp (Phillips Corrected Supp. Response, page 23, line 4 to page 24, line 19). Should the amount of equity returns have any bearing on the resource decision at issue here?**

A. No. PacifiCorp's resource planning considers the costs associated with a particular resource decision and does not, and should not, consider whether a component of a resource's cost is an equity return to PacifiCorp's shareholders or an equity return to a shareholder of an independent power producer. There is no logical reason that PacifiCorp would select a more expensive or higher-risk resource simply because it did not include an equity return to the company.

**Q. Mr. Phillips claims that the company would not have issued the 2017S RFP if the Utah Commission had not suggested doing so and that this demonstrates serious flaws in the 2017 IRP (Phillips Corrected Supp. Response, page 15, lines 1–9). How do you respond?**

A. As discussed above, the 2017S RFP provided a great deal of useful market information, but it will not ultimately result in the acquisition of solar resources because benefits of waiting are greater than the risks of moving forward now.

**Q. Do any other parties testify on the solar sensitivity results?**

A. Yes. Mr. Jenner testifies that "the modeling results I have reviewed indicate that the Combined Projects, together with the repowering proposals, are still the most cost-effective resource plan portfolio, and are not displaced by the solar portfolio which was modeled by Rocky Mountain Power." (Jenner Supp. Direct, page 3, lines 7–10). Mr. Jenner observed that it is somewhat counterintuitive that the company would need to make such a large capital investment to ultimately save customers money, but "when the capital investments themselves are reduced on account of the beneficial tax incentive programs, the fuel-cost savings over time can amount to substantial savings and relatively less expensive operating costs over the long-term planning cycle." (Jenner Supp. Direct, page 4, lines 3–14).

## RESOURCE NEED

**Q. Mr. Phillips continues to question the need for any new resources (Phillips Corrected Supp. Response, page 2, line 17 and page 25, line 3). Has Mr. Phillips provided any additional analysis supporting his claim that the Combined Projects are discretionary?**

A. No. In my rebuttal testimony, I explained in detail that the Combined Projects would displace higher cost, higher risk front-office transactions ("FOTs") in the near term and defer the need for other, higher-cost resources in the 2028 timeframe and therefore the Combined Resources meet a near-term and long-term resource need identified in the 2017 IRP. (Link Rebuttal, page 7, line 9 to page 17, line 4). Mr. Phillips did not dispute any these points made in my rebuttal testimony.

**Q. Is Mr. Phillips's position here consistent with WIEC's position in other cases?**

A. No. WIEC previously argued explicitly that FOTs represent a resource need that can be displaced by more cost-effective resources. Referring to PacifiCorp's 2015 IRP, WIEC previously argued that "it is not correct that PacifiCorp's IRP shows no need for additional resources for many years . . . To the contrary, the IRP demonstrates a *need* for significant resources every year, which PacifiCorp primarily proposes to secure through short-term FOTs."[9] WIEC's testimony in the same case claimed that the "IRP anticipates a *need* to acquire hundreds of thousands of megawatt hours every year through market purchases."[10]

Mr. Phillips's position here is contradicted by WIEC's prior briefing and testimony on resource need.

**Q. Is Mr. Phillips contradictory position on resource need important in this case?**

A. Yes. Mr. Phillips recommends several unprecedented conditions that the Commission should apply if it grants CPCNs for the Combined Projects, including disallowance of rate-base treatment for any turbine not in-service in time to receive 100-percent PTCs, a capital-cost cap that results in an automatic 21-percent disallowance, a lifetime cap on O&M and capital expenditures, imputation of the full estimated PTC benefits over the next 10 years, and total disallowance if the Combined Projects are not completed

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[9] *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. 20000-481-EA-15 (Record No. 14220), Joint Post-Trial Brief of the Rocky Mountain Coalition for Renewable Energy, the Wyoming Industrial Energy Consumers, Chevron Power and Energy Management Company, and EverPower Wind Holdings, Inc. at 8 (Apr. 19, 2016) (emphasis added).

[10] *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. 20000-481-EA-15 (Record No. 14220), Direct Testimony of Kevin C. Higgins on behalf of the Rocky Mountain Coalition for Renewable Energy, the Wyoming Industrial Energy Consumers, and Chevron Power and Energy Management Company at page 10, lines 19–21 (Jan. 4, 2016) (emphasis added).

(Phillips Corrected Supp. Response, page 41, line 10 to page 42, line 19). But Mr. Phillips justifies these conditions because he claims that the "Combined Projects are an opportunity investment for RMP" and therefore "it is appropriate to apply the traditional regulatory compact in reverse" to effectively guarantee customer benefits and eliminate customer risk. (Phillips Direct, page 7, line 21 to page 8, line 2; *see also* Phillips Direct, page 37, lines 6–8 (Combined Projects are "discretionary, and not designed to fulfill any resource requirement or other needs[.]"); Phillips Direct, page 3, lines 12–14 ("Wind Projects are not being pursued by RMP as a matter of need; rather, they are a discretionary project predominantly intended to harvest tax credits and increase RMP's rate base which might provide savings to ratepayers."). If the Combined Projects meet a resource need in the traditional sense, as WIEC previously acknowledged, then there is no basis for Mr. Phillips's conditions.

**Q. Has Mr. Phillips demonstrated that the Combined Projects pose greater risk to customers than increased reliance on FOTs in the near-term and the acquisition of a resource in 2028?**

A. No. Mr. Phillips recommends that customers be relieved of virtually all risk related to the Combined Projects, but has not demonstrated that customers will be exposed to higher or unreasonable risk because of the Combined Projects relative to the next best resource options. Just as there is no reason customers should be relieved of all risk related to FOTs, there is no reason customers should be relieved of all risk associated with the Combined Projects. Because the Combined Projects meet an identified resource need, there is no basis to apply conditions that represent a dramatic and unprecedented departure from well-established and long-standing regulatory principles.

**Q. Mr. Phillips notes the Oregon IE's recommendation for ratemaking treatment for the Combined Projects to support his proposed conditions (Phillips Corrected Supp. Response, page 39, line 7 to page 40, line 2). How do you respond?**

A. Mr. Phillips's proposed conditions go far beyond the recommendation of the Oregon IE. For example, the Oregon IE recommends a hard cap on the capital and O&M costs for the Combined Projects, Mr. Phillips recommends a hard cap *and a 21-percent disallowance.* Moreover, the Oregon IE's recommendation was intended to provide a comparable risk profile for utility-owned and PPA resources. Mr. Phillips's conditions are designed to remove customer risk regardless of the commercial structure, as evidenced by the fact his conditions were proposed before he knew whether the 2017R RFP would result in PPAs or utility-owned resources. Ultimately, the company believes that the Commission's existing ratemaking tools provide robust customer protections that do not require the imposition of unprecedented conditions on the Combined Projects.

**Q. Has any other witness addressed the company's assumption of risk if it pursues the Combined Projects?**

A. Yes. Mr. Freeman agrees that the company should not be solely responsible for endogenous risks that are beyond its control (Freeman Supp. Direct, page 12, lines 12–14). The company agrees with Mr. Freeman that the existing regulatory framework, reflected in the Commission's past practice, is sufficient to address risks that are beyond the company's control.

**Q. Have any other parties addressed the need for the Combined Projects?**

A. Yes. Mr. Lay testifies that he agrees with WIEC that there is no need for the Combined Projects because the company can meet its future resource needs using FOTs (Lay Supp. Direct, page 3, lines 11–16). Mr. Lay's reliance on WIEC's reasoning is flawed, for the reasons discussed above and in my rebuttal testimony.

**Q. Ms. Thompson claims that the company's 2017 IRP indicated that new wind and transmission investments in the preferred portfolio are unnecessary because: "For the foreseeable future, there is no significant capacity deficit, and load can be reliably met between a combination of existing resources and front office transactions." (Thompson Supp., page 4, lines 71–74). How do you respond?**

A. As described at length in my rebuttal testimony, the fact that the IRP includes FOTs means that there is a resource need that is not met by existing resources. If PacifiCorp can meet that need with resources that are lower cost and lower risk than FOTs, it is reasonable to do so. Ms. Thompson's testimony does not address or rebut any of the points made in my rebuttal testimony describing the relationship between resource need and FOTs.

**Q. Ms. Thompson also relies on generic nationwide data on load growth and anecdotes from California to justify her position that the Combined Projects are unneeded (Thompson Supp., page 5, line 98 to page 6, line 119). How do you respond?**

A. The information cited by Ms. Thompson is not relevant to the issues presented in this case because the data is not specific to PacifiCorp. As explained in my rebuttal testimony, the 2017 IRP demonstrates that there is a near-term resource need that can be met with FOTs or with new wind investments enabled by the Aeolus-to-Bridger/Anticline transmission line. The 2017 IRP concluded that a resource portfolio that includes the proposed new wind and transmission investments is the least-cost, least-risk portfolio, and that conclusion has been confirmed and strengthened over the course of this case.

**Q. Ms. Thompson also questions the value of wind generation and whether it can reliably displace thermal resources (Thompson Supp., page 6, line 129 to page 8, line 169). How do you respond?**

A. PacifiCorp’s 2017 IRP analysis compared new wind and transmission investments to all other available resource options, including market purchases, thermal resources, other renewable resources, and additional demand-side resources. The robust analysis in the IRP, which was confirmed in this case, demonstrates that wind resources are least-cost, least-risk even after accounting for their intermittency and resulting capacity-contribution value.

## MISCELLANEOUS ISSUES

**Q. Mr. Lay testifies that the “results of the 2017R RFP make it apparent that the competitive bidding process works,” but also indicated that there are problems with how QF prices are determined (Lay Supp. Direct, page 2, lines 19–20). Is this the correct forum for litigating QF pricing?**

A. No. Although the company may agree with Mr. Lay that its avoided-cost prices are too high, this case is not the proper forum for addressing QF policy and pricing.

## CONCLUSION

**Q. Please summarize the conclusions of your supplemental rebuttal testimony.**

A. As confirmed by two different IEs, the 2017R RFP was fair, transparent, and unbiased. The IEs found that the bids selected to the 2017R RFP final shortlist represent the top offers that are viable under current transmission planning assumptions, and the Utah IE found that the final shortlist bids should result in significant savings for customers. While solar resource bids submitted into the 2017R RFP may provide customer benefits, contrary to claims from certain parties, solar resource bids are not a superior resource alternative to the Combined Projects. When considering solar resource valuation risks, expected cost declines, and availability of the 30-percent ITC for solar projects coming online as late as 2021, PacifiCorp does not need to act now and has decided not to select any of the solar PPA bids to the 2017S RFP final shortlist. PacifiCorp will continue to reassess potential economic benefits from solar-resource opportunities in the 2019 IRP, considering a thorough assessment of valuation risks with full stakeholder engagement, to determine whether a new competitive solicitation process for projects capable of achieving commercial operation by the end of 2021 will provide customer benefits.

In contrast, the phase out of PTC benefits that are available for qualifying wind projects occurs sooner than the ramp down of ITC benefits that are available for solar resources, which requires that PacifiCorp must act now to deliver the new wind and needed transmission investments that will produce both near-term and long-term benefits for customers. This conclusion is supported by thorough and extensive economic analyses that is based on over 1,300 20-year simulations of PacifiCorp's system, which have been used to evaluate how the net benefits of the Combined Projects are affected by a variety of variables and uncertainties.

**Q. Does this conclude your supplemental rebuttal testimony?**

A. Yes.

**BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING**

| | | |
|---|---|---|
| **IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND NONTRADITIONAL RATEMAKING FOR WIND AND TRANSMISSION FACILITIES** | )<br>)<br>)<br>)<br>)<br>)<br>) | DOCKET NO. 20000-520-EA-17<br>(RECORD NO. 14781) |

**AFFIDAVIT, OATH AND VERIFICATION**

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

Affiant is the Vice President for PacifiCorp, which is a party in this matter.

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

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

Further Affiant Sayeth Not.

Dated this 13th day of March, 2018

Rick T. Link
Vice President
825 NE Multnomah St. Portland, OR 97232
(503) 813-7163

STATE OF OREGON )
) SS:
COUNTY OF MULTNOMAH )

The foregoing was acknowledged before me by Rick T. Link on this 13th day of MARCH, 2018. Witness my hand and official seal.

Notary Public

My Commission Expires: 10/26/2021

OFFICIAL STAMP
KELLY ANN WIGGINS
NOTARY PUBLIC-OREGON
COMMISSION NO. 968113
MY COMMISSION EXPIRES OCTOBER 26, 2021