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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Surrebuttal Testimony of Rick T. Link

May 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 SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. My surrebuttal testimony further supports the company's voluntary request for approval of a resource decision for the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") and request for approval of the significant energy resource decision to acquire the Ekola Flats, TB Flats I and II, and Cedar Springs wind facilities ("Wind Projects" and, collectively, the "Combined Projects"). Specifically, my testimony responds to the April 17, 2018 testimonies filed by the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Mr. Charles E. Peterson and Mr. Daniel Peaco; Office of Consumer Services ("OCS") witness Mr. Philip Hayet; the Utah Association of Energy Users ("UAE") and the Utah Industrial Energy Consumers ("UIEC") witness Mr. Bradley G. Mullins; and the Western Resource Advocates ("WRA") witness Ms. Nancy L. Kelly.

Q. Please summarize your testimony.

A. First, I present the results of economic analysis with the removal of the Uinta project from the list of wind projects for which the company is seeking approval. Second, I respond to claims that PacifiCorp does not have a resource need. Third, I address criticisms of PacifiCorp's 2017R Request for Proposals ("2017R RFP"). Fourth, I rebut criticisms of the company's economic analysis, which shows that the Combined Projects will generate significant customer benefits. Fifth, I address process criticisms.

Sixth, I address project risks. Finally, in response to claims that the Combined Projects may not be the least-cost, least-risk resource option, I summarize the economic analysis used to finalize PacifiCorp's 2017S Request for Proposals ("2017S RFP") bid-selection process.

My surrebuttal testimony demonstrates:

- The removal of the Uinta project does not negatively affect the economics of the Combined Projects. The Combined Projects (without Uinta) show benefits of $174 million in the medium case through 2050, and benefits of $338 million in the medium case through 2036. In the 18 scenarios studied (nine each for the 2050 and 2036 analyses), 16 of 18 cases show net customer benefits.

- Even after accounting for the updated load forecast that is summarized in my supplemental direct testimony, PacifiCorp has a 595-MW capacity deficit in 2021 that grows to 3,395 MW in 2036, and the Combined Projects are part of the least-cost, least-risk resource portfolio to meet this need.

- As supported by independent evaluators that were appointed and managed by two different state regulatory commissions, the 2017R RFP was fair, transparent, and unbiased.

- These independent evaluators 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 independent evaluator, 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. The economic analyses are robust, demonstrating that the Combined Projects are in the public interest and "most likely to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to customers." In fact, even though the company disagrees that a higher standard of review somehow applies in this case, the economic analyses demonstrate that the Combined Projects meet even this higher standard, with net customer benefits in 16 out of the 18 cases (meaning the Combined Projects have a high likelihood of providing benefits to customers).

- 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.

- The Company's 2036 integrated resource plan ("IRP") analysis shows that the Combined Projects are a lower cost resource than the solar resources in the medium case, even before considering the solar risk sensitivities. In the 2050 nominal revenue requirement analysis, the Combined Projects and the solar resources produce comparable net benefits in the medium case after accounting for the solar risk sensitivities. Moreover, if the construction of the Aeolus-to-Bridger/Anticline transmission line is included in the base case modeling in the 2050 analysis—consistent with the Company's and region's current long-term transmission plan—then the net benefits of the Combined Projects would be nearly $300 million higher than the solar resources in all cases.

- 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 through bi-lateral opportunities and in the 2019 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.

REMOVAL OF UINTA

Q. Ms. Cindy A. Crane states that the company removed Uinta from the wind projects for which the company is seeking approval to respond to parties' concerns and to align the request in this docket with the stipulations in Wyoming and Idaho. Please summarize the cost-and-performance attributes of the wind projects without Uinta.

A. With removal of the Uinta project, the total in-service capital cost for the remaining wind projects is approximately $[redacted] billion. Relative to the company's initial filing, the per-unit capital cost of the stipulated wind projects is down [redacted] percent from $1,590/kW to $[redacted]/kW. The power-purchase agreement pricing for 50 percent of the output of the Cedar Springs project is unchanged from what was described in my second supplemental direct testimony. And in aggregate, the Wind Projects are expected to operate at a capacity-weighted average annual capacity factor of [redacted] percent.

Q. What is the nominal value of PTCs relative to the in-service capital cost of the stipulated wind projects?

A. Over the first ten years of operation, the stipulated wind projects that will be owned by PacifiCorp will generate over $1.2 billion in PTC benefits, which is nearly 103 percent of the in-service capital for these wind facilities.

Q. Has the company updated the economic analysis of the Combined Projects based on the removal of the Uinta project?

A. Yes. First, I performed a spreadsheet analysis to estimate the high-level economic impact of removing the Uinta project. I performed this spreadsheet analysis for all nine price-policy scenarios previously described in my testimony. Consistent with the company's prior economic analysis, I provide these results based on the methodology used in the company's IRP through 2036 and using nominal revenue requirement projections through 2050.

Q. Please describe how you performed the high-level spreadsheet analysis.

A. Using data from the economic analysis presented in my supplemental direct and rebuttal testimony, I calculated the system benefits, including the Uinta Project, on a dollar-per-MWh basis for each price-policy scenario. I then multiplied these results by the expected generation from the Uinta project to estimate the annual system benefits associated with the Uinta project in total dollars. These system-benefit estimates were then netted against the same project-specific costs for the Uinta facility that were used in the economic analysis summarized in my second supplemental direct testimony. This calculation results in an estimate of the marginal net benefit or cost of removing the Uinta project for each price-policy scenario.

Q. Did you also update the economic analysis using the company's models?

A. Yes. I also re-ran the company's IRP models to remove Uinta under the medium natural gas, medium carbon dioxide ("CO_2") and low natural gas, zero CO_2 price-policy scenarios.

Q. Did you update any of the other inputs used in the analysis?

A. No. Other than removing Uinta, all the other inputs used in the economic analysis are the same as the inputs used in the company's second supplemental direct testimony filed on February 16, 2018.

Q. What is the high-level estimate of the economic impact of removing Uinta based on results through 2036?

A. Table 1-SR reports the high-level estimate of the economic impact of removing Uinta based on the results through 2036. These present-value revenue-requirement differential (“PVRR(d)”) results are shown alongside the results summarized in my supplemental direct and rebuttal testimony. The difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 1-SR: Estimated Impact of Removing Uinta
PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036

Price-Policy Scenario	Second Supplemental Direct Filing (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	($150)	($146)	($4)
Low Gas, Medium CO_2	($179)	($172)	($7)
Low Gas, High CO_2	($337)	($312)	($25)
Medium Gas, Zero CO_2	($319)	($296)	($23)
Medium Gas, Medium CO_2	($357)	($330)	($27)
Medium Gas, High CO_2	($448)	($410)	($38)
High Gas, Zero CO_2	($568)	($517)	($51)
High Gas, Medium CO_2	($603)	($548)	($55)
High Gas, High CO_2	($694)	($629)	($66)

Q. What conclusions can you draw from the results provided in Table 1-SR?

A. The high-level estimate based on results through 2036 shows that net benefits of the Combined Projects (without Uinta) are reduced by between $4 million and $66 million. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $27 million. Considering that results from the IRP models were used to select winning bids in the 2017R RFP, these findings confirm that it was reasonable to include Uinta in the 2017R RFP final shortlist, and that there could still be an opportunity to pursue this project to deliver customer benefits outside of this proceeding. Importantly, these results also show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects range between $146 million and $629 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $330 million.

Q. What is the high-level estimate of the economic impact of removing Uinta based on nominal revenue requirement results through 2050?

A. Table 2-SR reports the high-level estimate of the economic impact of removing Uinta based on the nominal revenue requirement results through 2050. These PVRR(d) results are shown alongside the results summarized in my second supplemental direct testimony. Like Table 1-SR above, the difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 2-SR: Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

Price-Policy Scenario	Second Supplemental Direct Filing (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	$184	$146	$38
Low Gas, Medium CO_2	$127	$97	$31
Low Gas, High CO_2	($147)	($145)	($2)
Medium Gas, Zero CO_2	($92)	($97)	$5
Medium Gas, Medium CO_2	($167)	($162)	($4)
Medium Gas, High CO_2	($304)	($283)	($20)
High Gas, Zero CO_2	($448)	($411)	($37)
High Gas, Medium CO_2	($499)	($456)	($43)
High Gas, High CO_2	($635)	($576)	($59)

Q. What conclusions can you draw from Table 2-SR?

A. The high-level estimate based on nominal revenue requirement results through 2050 shows that removal of Uinta reduces the net cost of the Combined Projects in three of the nine price-policy scenarios, and that the net benefits of the Combined Projects are reduced in six of the nine price-policy scenarios. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $4 million. Importantly, when the impact of net benefits are based on nominal revenue requirement results through 2050, these results show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects in the scenarios where they occur range between $97 million and $576 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $162 million.

Q. In a previous request for approval of a resource decision by the company, DPU used the simple average of the price-policy scenarios as a "risk-weighted benefit" that assumes each of the price-policy results is "equally likely." What is the risk-weighted benefit in this case?

A. Under the 2036 IRP modeling, the scenarios produce a risk-weighted net benefit of $373 million. Under the 2050 nominal modeling, the scenarios produce a risk-weighted net benefit of $210 million. *See In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4,* Docket No. 12-035-92, DPU Exhibit 2.0 SR, lines 52–58 (Feb. 28, 2013).

Q. What is the economic impact of removing Uinta based on updated results from the IRP model runs?

A. Table 3-SR reports the high-level estimate of the economic impact of removing Uinta alongside the updated modeled results using the 2036 and 2050 calculation methodologies. These results are presented for both the low natural gas, zero CO_2 and the medium natural gas, medium CO_2 price-policy scenarios. The table also shows the difference between the high-level estimate and the modeled results.

Table 3-SR: Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036			
Price-Policy Scenario	**High-Level Estimate (Without Uinta)**	**Modeled Result (Without Uinta)**	**Variance from Modeled Result**
Low Gas, Zero CO_2	($146)	($143)	($3)
Medium Gas, Medium CO_2	($330)	($338)	$8
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050			
Price-Policy Scenario	**High-Level Estimate (Without Uinta)**	**Modeled Result (Without Uinta)**	**Variance from Modeled Result**
Low Gas, Zero CO_2	$146	$154	($8)
Medium Gas, Medium CO_2	($162)	($174)	$12

Q. What conclusions can you draw from Table 3-SR?

A. First, the modeled results are similar to the high-level estimates described above, and consequently, the high-level estimates provide a reasonable representation of the impact of removing Uinta.

Second, under the medium natural gas, medium CO_2 price-policy scenario, the Combined Projects still provide net customer benefits when Uinta is removed. When calculated from IRP model results through 2036, customer net benefits are $338 million (down by $19 million from $357 million that was reported in my second supplemental testimony). When calculated from the nominal revenue requirement results through 2050, customer net benefits are $174 million (up by $7 million from the $167 million that was reported in my second supplemental direct testimony).

Third, under the low natural gas, zero CO_2 price-policy scenario, the Combined Projects still provide net customer benefits with Uinta removed when the PVRR(d) is calculated from IRP model results through 2036. Based on this methodology, customer net benefits are $143 million (down by $7 million from the $150 million benefit that was reported in my supplemental direct and rebuttal testimony). When calculated from the nominal revenue requirement results through 2050, net costs are $154 million (down by $30 million from the $184 million that was reported in my supplemental direct and rebuttal testimony).

Q. Have you calculated the change in capital costs that would have to occur to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario?

A. Yes. Removal of the Uinta project reduces capital costs for the Combined Projects to $[redacted] billion, as outlined by Ms. Joelle Steward. In-service capital costs would have to increase by approximately 11.1 percent (or $[redacted] million) to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario.

Q. Do the Combined Projects without Uinta still provide overall customer net benefits?

A. Yes. As set forth above, when using the IRP modeling, the Combined Projects still provide robust customer net benefits under all nine price-policy scenarios. Although the benefits have decreased slightly, they remain substantial. In addition, under the nominal revenue requirement view, the net benefits remained fairly consistent, increasing in some price-policy scenarios and decreasing in others. Although neither view is dispositive, each of these views provides important insight into how the Combined Projects are expected to impact the company's revenue requirement. Taken together, each of these views indicate that the removal of Uinta does not adversely impact the customer benefits, and the acquisition of the Combined Projects remains in the public interest.

Q. Does the removal of Uinta address the concerns raised by Mr. Peaco? (Peaco Supplemental Rebuttal and Surrebuttal, lines 673–736.)

A. Yes.

THE COMBINED PROJECTS ARE NEEDED TODAY

Q. Dr. Zenger and Messrs. Peaco, Hayet and Mullins continue to question the need for the Combined Projects. (Zenger Supplemental Rebuttal and Surrebuttal, lines 500–504; Peaco Supplemental Rebuttal and Surrebuttal, lines 365–367; Hayet Second Rebuttal, lines 127–135; Mullins Supplemental Rebuttal, lines 758–763.) Are these witnesses correct that there is no resource need now or in the next 10 years?

A. Absolutely not. In my rebuttal testimony, I explained in detail that PacifiCorp has an immediate resource need and that the Combined Projects 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. (Link Supplemental Direct and Rebuttal, lines 772-897.) Therefore the Combined Projects meet both near-term resource need and a long-term resource need as identified in the 2017 IRP.

Q. Mr. Mullins claims that the company's position on resource need is imprudent because it "disregards market access" when determining resource sufficiency. (Mullins Supplemental Rebuttal, lines 767–770.) Similarly, Dr. Zenger asserts that the Combined Projects do not meet an identified deficiency. (Zenger Supplemental Rebuttal and Surrebuttal, lines 500–502.) Do you agree?

A. No. In their interpretation of PacifiCorp's capacity position, Mr. Mullins and Dr. Zenger are effectively treating uncommitted FOT resources as existing resources that should be applied as a reduction to the company's projected capacity shortfall. This is contrary to basic least-cost planning principals, and more importantly, contrary to the IRP standards and guidelines adopted by the Utah Public Service Commission ("Utah Commission") in Docket No. 90-2035-01. Specifically, their positions are contrary to Guideline 4.b, which states that IRPs are to include: "An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis."

Mr. Mullins's and Dr. Zenger's position would require that PacifiCorp assess its resource need assuming that uncommitted FOT resources will always be available and that these resources should be used to offset a capacity shortfall regardless of cost. This would be an imprudent course of action. The real issue is not whether PacifiCorp has a resource need—it does—but whether the Combined Projects are lower cost and lower risk relative to other resource alternatives. PacifiCorp does not ignore FOTs in its IRP modeling, which is the exact same modeling used in this case. In fact, as I have described in previous testimony, FOTs must compete against all other resource options, including the Combined Projects, which is consistent with the Commission's IRP standards and guidelines.

Q. Dr. Zenger asserts that the company believes the Combined Projects will be "a better deal for ratepayers than FOTs, but it makes no representation that FOTs will be unavailable or unreasonably priced." (Zenger, Supplemental Rebuttal, lines 497–499.) How do you respond?

A. I agree that the Company's position (supported by robust economic analysis) is that, relative to all other resource alternatives—including FOTs—the Combined Projects are a better deal for customers. But this position isn't based on any assumptions that FOTs are "unavailable or unreasonably priced." The Company's position is that FOTs are available, but more expensive than the Combined Projects. The question is whether the Combined Projects are lower cost and lower risk than other resource alternatives, including FOTs. FOTs can be "reasonably priced," yet higher cost than other resource options. And this is precisely what the economic analyses in the 2017 IRP and throughout this proceeding, including the analysis summarized in my second supplemental direct testimony, shows—net customer benefits from a resource portfolio that includes the Combined Projects is less reliant on market purchases and is conservatively expected to generate net customer benefits in 16 of 18 modeled scenarios (nine price-policy scenarios over two different timeframes). Throughout this proceeding, the company has provided analysis that explicitly and overwhelmingly shows that the Combined Projects are superior to all other resource alternatives, including FOTs.

In contrast, Dr. Zenger has not adequately explained why it is in the public interest to pursue a resource portfolio that is more reliant on uncommitted FOTs considering that my economic analysis, which uses conservative assumptions, shows that the company's preferred portfolio would generate net benefits in all but two of 18 modeled scenarios.

Q. Mr. Peaco and Mr. Hayet state that the company has changed its rationale for justifying the Combined Projects. (*See* Peaco Supplemental Rebuttal and Surrebuttal, lines 112–126; Hayet Second Rebuttal, 28–30.) Is this accurate?

A. No. Mr. Peaco and Mr. Hayet appear to believe that the concepts of an economic time-limited opportunity and capacity need are mutually exclusive. Based on this view, Mr. Peaco and Mr. Hayet assert that PacifiCorp's justification for the Combined Projects has changed since the initial application was filed with the Commission last June. This is not true.

The Combined Projects were included in the 2017 IRP, filed with the Commission in April 2017, as an element of PacifiCorp's least-cost, least risk preferred portfolio, which includes resources *needed to reliably meet customer demand* over a 20-year time frame. PacifiCorp has not stated at any point in this proceeding that the Combined Projects are not needed to reliably serve our customers or are being proposed solely as an economic opportunity.

Mr. Peaco describes PacifiCorp's initial application by referencing the direct testimony of Ms. Cindy A. Crane describing the project as "a unique, time limited opportunity for the Company…." (Peaco Supplemental Rebuttal and Surrebuttal, line 121.) Mr. Peaco's omitted a portion of Ms. Cindy A. Crane's testimony, and these omissions change the testimony's meaning. Ms. Crane's testimony reads, in full: "The renewal of the PTCs has created a unique, time-limited *opportunity for the Company to construct critical transmission facilities in eastern Wyoming, while providing substantial customer savings.*" (Crane Direct, lines 206–210, emphasis added.)

Throughout this proceeding, the company has consistently stated that the Combined Projects will provide significant savings to customers and that they represent a unique, time-limited opportunity for the company to construct critical transmission facilities with minimal rate impact. This was true when the company filed its application in this docket and remains true today. The fact that the Company chose to highlight the unique, time-limited opportunity in direct testimony, then focus on need in response to parties' testimony arguing that there is no need does not indicate that the Company "changed positions."

The Combined Projects are unique in that they provide an opportunity to procure resources needed to meet a capacity deficit while delivering economic benefits and much-needed transmission facilities. This is a time-limited opportunity because of expiring PTCs. Contrary to Mr. Peaco's and Mr. Hayet's mischaracterization of the company's application and position in this proceeding, the Combined Projects are both an economic opportunity *and* needed. Mr. Hayet even goes so far as to state: "Had the Company's request been based on a resource need, the June 30, 2017 application would have had an entirely different emphasis." Mr. Hayet is wrong. The Company chose to highlight the benefits of the project in the June 30, 2017 application because the need had been firmly established through the 2017 IRP. The parties' challenge to the need for the project—despite the fact that the company is capacity deficient over all years in the 2017 IRP—was surprising.

Q. Mr. Peaco claims that you noted in your direct testimony "that the resource balance analysis performed for the 2017 IRP showed no need for incremental capacity until 2028 and had no mention of FOTs as a factor." (Peaco Supplemental Rebuttal and Surrebuttal, lines 123–125.) Mr. Hayet similarly states that "the IRP indicated that the Combined Projects were not needed to satisfy…the Company's capacity requirements." (Hayet Second Rebuttal, lines 842–844.) Are these assertions accurate?

A. No. In my direct testimony, I stated that "the load-and-resource balance developed for the 2017 IRP shows that PacifiCorp would not require incremental system capacity to meet its 13-percent planning-reserve margin until 2028, *accounting for assumed coal unit retirements, incremental energy efficiency savings, and available wholesale-power market purchase opportunities*." (Link Direct, lines 111–115, emphasis added.) The term "available wholesale-power market purchase opportunities" used in this statement is a direct reference to uncommitted FOTs and is factually accurate. If one assumes that all available FOTs are procured without regard to cost—which as noted above is apparently what the parties are suggesting and is essentially treating these resources as existing resources—then there would not be a capacity shortfall until 2028. My direct testimony was highlighting that the selection of wind resources before 2028 was a strong indication that these resources would provide customer benefits because they are lower cost than uncommitted FOTs.

Q. Mr. Hayet argues that the fact that the company did not include the Aeolus-to-Bridger/Anticline transmission line as in service in 2024 in its "status quo case in its modeling analysis" indicates the company does not "really believe the transmission line would have to be constructed by 2024…." (Hayet Second Rebuttal, lines 860–862.) Is this a reasonable position?

A. No. Mr. Hayet's position would penalize the company for being conservative in its modeling assumptions. In fact, if the cost for the Aeolus-to-Bridger/Anticline transmission line were included in the base case simulations beginning 2024 (as assumed in PacifiCorp's long-term transmission plan) and assuming no change to in-service capital costs, net customer benefits would increase in all price-policy scenarios by $193 million when assessed through 2036 and by $293 million when assessed through 2050. Including this cost in the base case simulations would result in net customer benefits under all price-policy scenarios (even in the low natural gas, zero CO_2 price-policy scenario), whether analyzed through 2036 or 2050, and highlights a material risk under a "do nothing" scenario.

Q. Both Dr. Zenger and Mr. Peterson assert that you are now arguing that the Combined Projects are an "early acquisition." (Zenger Supplemental Rebuttal and Surrebuttal, lines 512–553; Peterson Supplemental Rebuttal and Surrebuttal, lines 407–410.) Is this an accurate representation of your testimony?

A. No. Dr. Zenger and Mr. Peterson misunderstand my testimony. In response to arguments that this is not an ordinary resource acquisition, I stated: "*At the very least*, the Combined Projects are an early acquisition." (Link Supplemental Direct and Rebuttal, lines 1082–1083, emphasis added). Interpreting this statement to mean that I "admitted" this is an early acquisition, as Dr. Zenger does, ignores the remainder of my testimony in this docket, which clearly and repeatedly states that there is both a near-term need and long-term need for the Combined Projects, as well as the testimony of Mr. Rick A. Vail.

Q. Mr. Mullins claims that the capacity need identified in the 2017 IRP no longer exists when the company's assessment of resource need is updated to account or the most recent, lower load forecast. (Mullins Supplemental Rebuttal lines 779–815.) Is this true?

A. No. In 2021, the first full year that the Combined Projects are in service, the 2017 IRP shows a capacity deficit of 1,023 MW. The updated load forecast summarized in my supplemental direct testimony shows a 428-MW reduction to the coincident peak load forecast in 2021 relative to the load forecast used in the 2017 IRP. Consequently, accounting for the updated load forecast from my supplemental direct testimony, PacifiCorp's capacity deficit in 2021 would be 595 MW (1,023 MW capacity deficit less the 428-MW reduction in coincident peak load). Accounting for this updated load forecast, PacifiCorp's capacity need grows to 3,395 MW by 2036. The capacity contribution of the Combined Projects (without Uinta) is 182 MW (1,150 MW nameplate capacity times 15.8 percent capacity contribution), which is well below the 595 MW of capacity need in 2021 and the 3,395 MW of capacity need in 2036, even after accounting for the updated load forecast used in my supplemental direct testimony.

Q. Did PacifiCorp provide an updated load-and-resource balance in its 2017 IRP Update?

A. Yes. PacifiCorp filed its 2017 IRP Update with the Commission on May 1, 2018. The load forecast used to develop the updated load-and-resource balance in the 2017 IRP Update is the same underlying load forecast that was used in the economic analysis described in my supplemental direct testimony. After accounting for changes in resources and this updated load forecast, the load-and-resource balance in the 2017 IRP Update shows a capacity shortfall of 606 MW in 2021, rising to 3,445 MW by 2036. As noted above, the capacity contribution of the Combined Projects (without Uinta) is 182 MW, which is well below the capacity need identified in updated load-and-resource balance in the 2017 IRP Update.

Q. Mr. Mullins's Confidential UAE-UIEC Exhibit 3.2 attempts to demonstrate that there is no meaningful need for the Combined Projects, and virtually no need for FOTs. (Mullins Supplemental Rebuttal, lines 790–797.) Is his analysis correct?

A. No. Mr. Mullins's calculations misapply hourly load forecast data provided in response to UAE Data Request 5.6. This hourly load forecast data is net of reductions from distributed generation and incremental demand-side-management ("DSM") resources. These items are accounted for separately in Table 5.14 in PacifiCorp's 2017 IRP. Consequently, Mr. Mullins's calculations double count the impact of distributed generation and incremental DSM resources in his attempt to estimate the impact of the updated load forecast on PacifiCorp's load-and-resource balance. Contrary to Mr. Mullins's claims, which are based on faulty calculations, after accounting for the updated load forecast, PacifiCorp continues to show an immediate need for new capacity that exceeds the capacity contribution from the Combined Projects. When accounting for the Combined Projects, PacifiCorp will still need to acquire 424 MW of uncommitted in FOTs in 2021 to maintain a 13-percent planning-reserve margin.

Q. Is the company's position in this case regarding the treatment of FOTs in determining resource need consistent with prior resource acquisition dockets?

A. Yes. When PacifiCorp acquired the Lakeside 2 plant, it developed an updated assessment of resource need to support the competitive solicitation process. In that case, the company described that its updated assessment included certain planned resources from its most recent IRP (the 2008 IRP) and then excluded resources that were eligible to be filled by the resources that bid into the RFP. According to PacifiCorp's need assessment, the "portfolio set-up reflects the appropriate capacity gap for resource selection optimization by the Company's capacity expansion model, System Optimizer." *In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals*, Docket No. 10-035-126, All-Source Request for Proposal Resource Needs Assessment Update at 6 (Oct. 7, 2010). Among the resources removed to create the capacity gap that would be filled by the RFP bids were uncommitted FOTs. Thus, in the Lakeside 2 acquisition analysis, PacifiCorp did not determine its resource position by accounting for all available FOTs. Instead, the company removed the FOTs from its load-and-resource balance to create the capacity need and then let FOTs compete with the resource bids in the RFP process to select the optimal resource portfolio. PacifiCorp is using the same approach here.

Q. Did parties in that case object to the company's treatment of FOTs in determining resource need?

A. It does not appear so. In fact, OCS's testimony in that case described the company's load-and-resource balance without considering FOTs when it analyzed the potential need for additional resources. *In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals*, Docket No. 10-035-126, Witness OCS-1D, lines 62–70 (Mar. 3, 2011). DPU's expert in the Lakeside 2 case also testified that resources from the RFP could be used to displace FOTs. In particular, DPU testified that a second gas plant (the "Apex plant"), in addition to Lakeside 2, could decrease the reliance on FOTs, which "demonstrate[d] that the Apex plant is needed and can make a vital contribution to the Company's negative capacity position." *In the Matter of the*

Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals, Docket No. 10-035-126, Exhibit No. DPU 2.0 at 31-32 (Mar. 3, 2011).

Q. Mr. Peterson asserts that PacifiCorp has "routinely dismissed any [DPU] concerns about front office transactions until the past few months when it discovered a 'need' to replace front office transactions with multi-billion dollar rate base proposals first announced at the very end of the latest IRP process." (Peterson Supplemental Rebuttal and Surrebuttal, lines 496–499.) Is this true?

A. No. Having led the IRP process for several years and having participated in a number of competitive solicitation processes, I am aware of DPU's persistent concerns about relying on FOTs to meet the company's 13-percent planning-reserve margin target. For this reason, I have been surprised by DPU's arguments supporting increased reliance on uncommitted FOT resources in its opposition to the Combined Projects. Finally, I do not agree with Mr. Peterson's assertion that the company has dismissed DPU's concerns with FOTs. Up until now, all other resource alternatives have simply been higher cost.

Q. Dr. Zenger states that the company has not provided any indication that, without the Combined Projects, customers "will not be reliably served at a reasonable cost in the future." (Zenger Supplemental Rebuttal and Surrebuttal, lines 589–591.) How do you respond?

A. Dr. Zenger's testimony implies that resources should only be acquired to meet a projected capacity need only when *all* resource alternatives have been exhausted and the company is on the verge of not being able to reliably serve its customers. In fact, Dr. Zenger goes as far to assert that new resource acquisition should only be pursued in the absence of an adequate, reliable, and reasonably priced system. (Zenger Supplemental Rebuttal and Surrebuttal, lines 474–475.) Dr. Zenger's perspective on this issue is extreme and would require that the company manage its system on the very edge of being able to deliver reasonably priced service for our customers. As the individual responsible for PacifiCorp's resource plan, it is my goal to ensure the company does not find itself in position where its only choice is to acquire a resource or risk reliability.

Q. Dr. Zenger states there is little downside risk to not pursuing the Combined Projects. (Zenger Supplemental Rebuttal and Surrebuttal, lines 591–592.) Mr. Peaco similarly asserts that customers will be "reliably serviced at a reasonable cost in the future" without the Combined Projects and "there is little downside risk for customers in the Combined Projects' absence." (Peaco Supplemental Rebuttal and Surrebuttal, lines 357–359.) Do you agree?

A. No. There are material risks if the Combined Projects are not constructed. Without the Combined Projects, customers would be more exposed to volatility in the market, more exposed to policies that could place a cost on CO_2 emissions, and more at risk of having to incur the cost of the Aeolus-to-Bridger/Anticline transmission line without the benefit of having PTC-eligible wind to offset these costs. As noted above, and without even accounting for market price and CO_2 policy risks, this could burden customers with hundreds of millions of dollars in costs that are not factored into the company's economic analysis. In fact, the company's conservative economic analysis demonstrates that the "do nothing" scenario will *increase* customer costs in 16 of 18 price-policy scenarios.

2017R RFP MODELING AND RESULTS

Q. Please summarize the role of the independent evaluators who monitored the 2017R RFP.

A. The 2017R RFP was overseen by two independent evaluators—one appointed and retained by the Utah Commission, and one appointed by the Public Utility Commission of Oregon ("Oregon Commission") and retained by PacifiCorp. In accordance with the statutes, rules, and policies in Utah and Oregon, the independent evaluator is an *independent* expert appointed and managed by the commission (not PacifiCorp) to ensure that the RFP process was conducted in a fair and unbiased manner and the final shortlist projects are reasonable and consistent with the modeling results used to evaluate bids.

In the 2017R RFP, both independent evaluators 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 independent evaluators had complete and unrestricted access to all information related to the 2017R RFP and kept both independent evaluators informed of developments as they occurred.

Q. Did the independent evaluators 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 independent evaluators 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. Oregon's final independent evaluator report, issued in February 2018, is provided as Highly Confidential and Confidential Exhibit RMP___(RTL-1SR) ("Oregon IE Report"), and Utah's final independent evaluator report, also issued in February 2018, is provided as Highly Confidential and Confidential Exhibit RMP___(RTL-2SR) ("Utah IE Report").

Q. Did the independent evaluators' review confirm the reasonableness of the benchmark bids?

A. Yes. The Utah independent evaluator concluded that (1) PacifiCorp provided detailed information related to the benchmarks that exceeded industry standards, (2) cost estimates were reasonable, and (3) the review, assessment, and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward perception of bias. (Utah IE Report at 44-45.)

The Oregon independent evaluator 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." (Oregon IE Report at 10.) To make its assessment, the Oregon independent evaluator "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." (*Id.*) This "comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors." (*Id.*) The Oregon independent evaluator 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 with public data and were supported by credible third-party analysis.

(*Id.* at 10–11.)

Q. Did the independent evaluators provide any overall conclusions related to the 2017R RFP?

A. Yes. The Utah independent evaluator supported the final shortlist projects based on the following conclusions:

- The 2017R RFP was fair, reasonable, and generally in the public interest. (Utah IE Report at 70.)
- 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 build-transfer agreement ("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.)

The Oregon independent evaluator also 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 independent evaluator's 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 independent evaluator's analysis included its own cost models for each bid option and a review of PacifiCorp's models.
- The independent evaluator took special care to confirm the selection of PacifiCorp's benchmark resources. The independent evaluator confirmed the accuracy of the benchmark costs and scoring. The independent evaluator noted that the benchmark bids were disciplined by the fact that a third-party bidder submitted a competing offer for a BTA for benchmark projects.

- The independent evaluator confirmed that the 2017R RFP aligns with the 2017 IRP.

(Oregon IE Report at 2–3.)

Q. Please respond to Messrs. Peaco's, Hayet's and Mullins's claims that PacifiCorp's changes to its economic modeling for purposes of developing the final shortlist for the 2017R RFP unfairly biased the results. (Peaco Supplemental Rebuttal and Surrebuttal, lines 842–859; Hayet Second Rebuttal, lines 353–356; Mullins Supplemental Rebuttal, lines 463–468.)

A. As explained in my supplemental direct testimony, when comparing bids in the 2017R RFP portfolio development phase, PTC benefits were applied on a nominal basis rather than a levelized basis for self-build and BTA bids to better reflect how the PTC benefits flow through customer rates. (Link Supplemental Direct and Rebuttal, lines 38-41.) This refinement better aligns project costs and benefits and impacts only the SO model and 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 testimonies.

This modeling refinement was necessary as part of the 2017R RFP bid evaluation and selection process because this was the first time that the SO model was used to select PTC-eligible wind proposals offered under different commercial structures where those commercial structures directly influence the magnitude and timing of expected costs in customer rates. Under company-owned commercial structures (benchmarks and BTAs), PTC benefits will flow through to customer rates over the first ten years after those wind facilities are placed in service. In contrast, wind facilities offered into the 2017R RFP as a PPA were not priced by bidders to reflect the substantial near-term benefits of PTCs. The difference in present-value customer impacts between these two types of commercial structures has not traditionally been a factor in an IRP, where all proxy wind resources are assumed to be company-owned assets for planning purposes. The company's modeling refinement did not bias the results of the 2017R RFP as Mr. Peaco, Mr. Hayet and Mr. Mullins claim. To the contrary, this modeling improvement was necessary to ensure bid selections appropriately accounted for the timing of PTC benefits between company-owned and PPA commercial structures.

Q. Did you continue to use levelized capital costs during the portfolio development phase of the 2017R RFP bid evaluation and selection process?

A. Yes.

Q. Why is it appropriate to reflect nominal PTCs while continuing to levelize capital revenue requirement in the 20-year modeling through 2036?

A. The IRP models select least-cost portfolios based on present-value system costs. It would not be appropriate to include nominal revenue requirement from capital investments for assets having a depreciable life that extends beyond the 20-year IRP study period in any present-value calculation. It would only be appropriate to include capital revenue requirement on a nominal basis in present-value calculations when those calculations cover the full life of the proposed new wind facilities.

In contrast, it is appropriate to consider nominal PTC benefits in the IRP models because all of these benefits will be realized within the 20-year time frame of those studies. Because PTC benefits will be fully realized within the 20-year time frame of these studies, the impact of applying nominal PTCs when developing present-value calculations is precisely the same impact that would occur if PTCs were levelized over their 10-year life. Consequently, with the improved modeling methodology, PacifiCorp's IRP models appropriately weight the front-end loaded PTC benefits without disproportionately weighting capital costs in its present-value calculations.

This improved treatment of PTCs simply ensures that present-value calculations in the 20-year analysis are based on a stream of annual costs and benefits that consistently applies levelization over the period in which those costs and benefits are expected to occur—30 years for capital revenue requirement, 10 years for PTC benefits, and annually for non-PTC system benefits and run-rate O&M.

The company used this approach—ensuring that present-value calculations reflect costs and benefits that are levelized over the period in which they are expected to occur—without controversy when it requested approval of its voluntary resource decision 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 improved modeling used here simply conforms the treatment of PTCs to the treatment of other costs and benefits.

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 adopted this same treatment in its recently filed 2017 IRP Update and intends to use this approach in future IRPs.

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

A. No. Both independent evaluators overseeing the 2017R RFP were informed 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 sensitivity analysis requested by the independent evaluators that I described in my supplemental direct testimony was designed to specifically test whether the refined modeling of PTC benefits unreasonably biased the resource selection. (Link Supplemental Direct and Rebuttal, lines 252–277.)

Q. Did the Utah independent evaluator discuss this treatment of PTCs in the portfolio-development phase of the 2017R RFP?

A. Yes. The Utah independent evaluator 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 independent evaluator described the additional analysis provided by the company, along with several meetings with the independent evaluators to discuss this issue. The Utah independent evaluator 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 independent evaluator, 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 independent evaluators, the Utah independent evaluator confirmed his conclusions from the portfolio-development stage, explicitly concluding that the revised shortlist portfolio provides greater near-term benefits than the PPA sensitivity:

> 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 independent evaluator conclude that the self-build or BTA bids received a preference as a result of PacifiCorp's modeling?

A. No, quite the opposite. The Utah independent evaluator concluded that the results of the 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 independent evaluator 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. Did the Oregon independent evaluator discuss this treatment of PTCs in the portfolio development phase of the 2017R RFP?

A. Yes. The Oregon independent evaluator expressed concern that levelizing the PTC benefits caused the SO model to select PPAs instead of self-build and BTA bids. (Oregon IE Report at 29-30.) The Oregon independent evaluator 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 sensitivity requested by the independent evaluators were ultimately non-viable projects. (Oregon IE Report at 5.)

Q. Mr. Mullins claims that the RFP selection process was biased because the Company “disqualified” projects based on interconnection queue position (Mullins, Supplemental Rebuttal, lines 275–413.) Mr. Peaco also identifies the “last minute elimination of essentially all projects” due to the restudy process as a “significant failure” in the RFP process. (Peaco Supplemental Rebuttal and Surrebuttal, lines 379–381.) And Mr. Hayet likewise claims that the company “determined bids had to be eliminated….” (Hayet Second Rebuttal, lines 726–730.) Are the witnesses accurately describing the impact of the interconnection restudies on the RFP process?

A. Absolutely not. No bids were “disqualified” or “eliminated” from consideration due to interconnection queue position. The final shortlist was initially developed based on economic analysis of the bids—without consideration of interconnection queue position, as discussed in more detail below. Only one change to the final shortlist was made based solely on the results of the interconnection restudies—the removal of McFadden Ridge II because it could not be interconnected with just the addition of the Aeolus-to-Bridger/Anticline transmission line.

Even more importantly, any allegations that the interconnection queue issues “biased” the RFP process are directly contrary to the conclusions of the independent evaluators who monitored the 2017R RFP. Both independent evaluators provided their own independent analysis and carefully scrutinized the process and results. And both independent evaluators concluded that the 2017R RFP was transparent, fair, and unbiased.

Q. You note that the independent evaluators addressed the interconnection queue issue. What did the independent evaluators conclude?

A. Yes. Both independent evaluators agreed with PacifiCorp's assessment that projects with interconnection queue positions lower than Q0712 were non-viable. Although both independent evaluators expressed some frustation about the limitations imposed by these issues, both concluded that the process was nonetheless fair, transparent, and unbiased. The Utah independent evaluator found that the final shortlist of projects "was a reasonable selection based on the constraints identified." (Utah IE Report at 84.) The Oregon independent evaluator 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 independent evaluator 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 independent evaluator, "[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 independent evaluators disagree with Mr. Mullins's claim notable?

A. Yes. Mr. Mullins appears to only selectively rely on the independent evaluators, citing their conclusions when they support his position, but ignoring or dismissing their conclusions when they do not support his position.

Q. Mr. Mullins claims that the company never disclosed the possibility that a bidder's interconnection queue position could impact the viability of its project. (Mullins Supplemental Rebuttal, lines 175–187; 209–217; 211–224; 291–300.) Is this accurate?

A. No. The fact that there was limited interconnection capability was known at the beginning of the 2017R RFP process, which is why PacifiCorp's initial minimum bid-eligibility screen included a requirement for an interconnection system impact study. Commenters and bidders requested that this requirement be removed from the minimum bid-eligibility screen to allow broader participation. At the recommendation of the independent evaluators, this restriction was changed to generators who had begun the interconnection study process.[1] 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 of the independent evaluators indicated that the 2017R RFP process was biased or unreasonable as a result.

[1] *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).

Q. Mr. Peterson also reiterates the Utah IE's claim that the company should have held a transmission workshop during the RFP process so that potential bidders understood the interconnection constraints on the Company's system. (Peterson Supplemental Rebuttal and Surrebuttal, lines 118–122.) Was the transmission workshop referenced by the Utah IE actually held?

A. Yes. Contrary to the IE's final report, the company did hold the transmission workshop. PacifiCorp identified in its released RFP that it would reserve a specific time in its October 2, 2017 bidder workshop to cover interconnection and transmission service issues and followed through with specific discussions on the topic, as noted in its bidder workshop presentation deck. PacifiCorp also responded to multiple bidder questions on interconnection and transmission service, reviewed those with the independent evaluators, and posted the responses to the RFP website.

Q. Mr. Mullins also claims that the company's "treatment of transmission costs" was inconsistent with its communications with bidders in the period leading up to the 2017R RFP. Is this true?

A. No. Mr. Mullins claims that contrary to communications with bidders, the company directly assigned to bidders with queue positions at Q713 or higher the "costs associated with providing transmission capacity in order to relieve existing congestion and facilitate the interconnection and integration of new wind projects"—including the costs of Gateway South. (Mullins Supplemental Rebuttal, lines 228–241.) Mr. Mullins is wrong.

Mr. Mullins correctly states that the company informed bidders that costs associated with the Aeolus-to-Bridger/Anticline transmission line, which relieves congestion and enables interconnection, would not be assigned to individual projects. And this is exactly what PacifiCorp did in the bid-evaluation project. Contrary to Mr. Mullins's claims, at no point did PacifiCorp put the costs of any component of PacifiCorp's long-term plan on bids (whether the Aeolus-to-Bridger/Anticline line or other elements of Energy Gateway).

To the extent Mr. Mullins is claiming that PacifiCorp told bidders that interconnection costs required to receive *interconnection* service, which are specific to any individual wind facility, would not be accounted for in the company's bid selection and evaluation process, he is incorrect. One of the minimum bid-eligibility requirements explicitly identified in the 2017R RFP clearly states that bids could be disqualified if bidders failed to provide interconnection costs. In specifying this minimum bid-eligibility requirements, the 2017R RFP document further states that cost estimates are required even if a study from the transmission provider was not completed or available at the time bids were due. Clearly, PacifiCorp would not have established this minimum bid-eligibility requirement, which if not met could disqualify a bid, if it did not intend to use this information to evaluate bids submitted into the 2017R RFP.

Q. Mr. Mullins claims that he was "under the impression that the bids would be evaluated on the same basis," including equalization or mitigation of any benefits that one bidder may have due to queue position. (Mullins Supplemental Rebuttal, lines 277–289.) How do you respond?

A. As described throughout my previous testimony and this testimony, the bids *were* evaluated on the same basis. Mr. Vail addresses Mr. Mullins's unfounded allegations that PacifiCorp could have somehow addressed queue position through bid analysis.

Q. Mr. Mullins claims that because "PacifiCorp applied incremental transmission costs to the bids whose queue position exceeded the incremental transmission capacity, the higher queue position resources had no way of being selected by the model." (Mullins Supplemental Rebuttal, lines 320–328.) Is this true?

A. No. In fact, my supplemental direct testimony describes the bid evaluation and selection process that was completed *before* considering the results of the interconnection restudy process. The original final shortlist of bids summarized in that testimony included the same projects selected to the updated final shortlist summarized on my second supplemental direct testimony except that the original final shortlist included the McFadden Ridge II benchmark bid. In direct contradiction to the claims made by Mr. Mullins, the original bid evaluation and selection process performed by PacifiCorp and monitored by two independent evaluators demonstrates that the interconnection restudy process did not prevent, in any way, the selection of projects because of their interconnection queue number.

Q. Based on this understanding, Mr. Mullins then argues that there is no way to know if the best resources were actually selected to the final shortlist. (Mullins Supplemental Rebuttal, lines 320–328.) Is this true?

A. No. As discussed above, Mr. Mullins's assertion is contrary to basic facts and, therefore, fundamentally flawed. Before considering results of the interconnection restudy process, the only interconnection-related constraint was the assumption that total interconnection capability with the addition of the Aeolus-to-Bridger/Anticline transmission line would be 1,270 MW. The interconnection restudies performed after the original final shortlist was determined resulted in the following conclusions:

(1) That the TB Flats I and II and Cedar Springs projects could interconnect with the addition of the Aeolus-to-Bridger/Anticline transmission line and no other elements of the company's long-term plan;

(2) That McFadden Ridge II could not interconnect without additional elements of the company's long-term transmission plan, namely Gateway West and Gateway South; and

(3) That additional interconnection capability would be created with the addition of the Aeolus-to-Bridger/Anticline transmission line, which allowed McFadden Ridge II to be replaced with Ekola Flats.

Rather than limiting the outcome of the 2017R RFP, the interconnection restudy process provided new information that allowed the inclusion of a more economic project because of increased interconnection capability. The only thing that was preventing the models from choosing Ekola Flats over McFadden Ridge II in development of the original final shortlist was the original 1,270-MW limit on interconnection capability.

Mr. Mullins also ignores the fact that the interconnection considerations resulted in PacifiCorp proposing to replace *only one shortlist bid*, with all other shortlist bids remaining unchanged. More specifically, the interconnection restudy process provided new, more updated information that caused PacifiCorp to exclude the McFadden Ridge II benchmark bid. While the new and more updated information from the interconnection restudy process demonstrates that projects with an interconnection queue number greater than Q0712 would not be viable at this time, this information had no impact on selection of the best resources other than allowing the more-economic Ekola Flats benchmark bid to replace the McFadden Ridge II benchmark bid.

This single shortlist change resulting from interconnection restudies can hardly be described as interfering with the value of the company's entire competitive solicitation process. Allowing participation without regard to interconnection queue position or study status resulted in a robust competitive solicitation, including numerous bids that were not enabled by construction of the Aeolus-to-Bridger/Anticline transmission line. Interconnection considerations, based on the most current and up-to-date information, caused the replacement of a single project and did not unravel those benefits. To the extent Mr. Mullins is arguing that the original (pre-interconnection considerations) shortlist should have included lower-queued projects for other, non-interconnection-related reasons, these arguments are inconsistent with the results of the economic evaluation of the bids and should be disregarded.

Q. Mr. Mullins claims that PPA bids were lower risk and therefore better alternatives and that these alternatives were eliminated based only on their interconnection queue position. (Mullins Supplemental Rebuttal, lines 322-340.) Is this true?

A. No. As described above, the preliminary shortlist of bids that was selected *before* the interconnection restudy process was finalized included all but one of the same resources that are included in the updated final shortlist. Moreover, as discussed in my supplemental direct testimony, at the request of the independent evaluators, PacifiCorp conducted a sensitivity to specifically test whether the highest performing PPAs bid into the RFP could displace the bids selected to the preliminary shortlist. This sensitivity study, which did not impose any limitations on resource selection based on interconnection queue position, shows that the PPAs were not superior resource selections.

Q. Mr. Mullins 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 and PTC "unavailability"). (Mullins Supplemental Rebuttal, lines 329–340.) How do you respond?

A. I disagree. Mr. Mullins ignores the fact that customers also receive upside benefits for utility-owned resources that they do not receive under a PPA. For example, customer benefits from the Combined Projects associated with reduced O&M costs, increased generation levels, and terminal value provide customer benefits that are not available through a PPA. 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.

UPDATED ECONOMIC ANALYSIS

Q. Messrs. Peaco, Hayet, and Mullins and Ms. Kelly claim that the nominal treatment of PTCs has the potential to bias model results for the 20-year study period and does not provide a reasonable estimate of both the costs and the benefits of the Combined Projects. (Peaco Supplemental Rebuttal, lines 842–859; Hayet Supplemental Rebuttal, lines 303–466; Mullins Supplemental Rebuttal, lines 437–474; Kelly Response Testimony, lines 132–137.) How do you respond?

A. As I discussed earlier, the rationale for applying PTC benefits on a nominal basis is reasonable and necessary to align the 20-year economic analysis with how PTC benefits will flow through to customers in rates. It is appropriate that the company continue to apply revenue requirement associated with capital costs on a levelized basis, because when setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset, which extends beyond 2036 (the last year of the 20-year modeling period). In contrast, PTC benefits will flow to customers during the first 10 years after the new equipment is installed at the proposed wind facilities. Consequently, the timing of the PTC benefits should be appropriately weighted and accounted for in the present-value calculation of net benefits.

Q. Mr. Hayet calculates the 20-year benefits from the Combined Projects (with Uinta) using nominal capital costs with nominal PTCs and concludes that the benefits in each price-policy scenario drop by $75 million. (Hayet Second Rebuttal, lines 425–448.) How do you respond?

A. On its face, it is perfectly rational to consider nominal revenue requirement for capital investments over any time period. However, for the reasons described in my supplemental direct testimony and in this surrebuttal testimony, it is not appropriate to include nominal revenue requirement from capital investments for assets having a depreciable life that extends beyond the 20-year IRP study period in *present-value* calculations based on model results through 2036. Mr. Hayet asserts that the 20-year analysis, with the application of levelized capital costs, understates revenue requirement and that his calculations inappropriately estimate the impact of this assumption in single present-value figure. This is particularly problematic when including nominal revenue requirement costs for transmission facilities assumed to have a 62-year life, where these assets are expected to be in service for additional 46 years beyond the 20-year IRP planning period. Mr. Hayet fails to recognize that the present-value results from the IRP models are intended to assess the relative difference in system costs among different resource portfolios over a 20-year planning time frame. The present-value results from the IRP models are not intended to forecast annual rate impacts between different resource portfolios.

Throughout this proceeding, my testimony has presented an annual revenue requirement analysis of the Combined Projects to specifically address directional rate implications in nine different price-policy scenarios. In this analysis, it is appropriate to consider the nominal revenue requirement from capital costs in the present-value calculations because it spans the full 30-year life of the new wind facilities. Importantly, as summarized earlier in my testimony, the present-value results from the nominal revenue requirement analysis demonstrate that the Combined Projects (without Uinta) are conservatively expected to produce net customer benefits in seven of nine price-policy scenarios, and these benefits are expected to occur over both the near and long terms. Importantly, even if one were to assume that Mr. Hayet's present-value calculations are valid for the 20-year IRP analysis—and to be clear, the company is not saying this calculation is valid—the Combined Projects still generate net customer benefits in seven of the nine price-policy scenarios. In fact, Mr. Hayet's table summarizes 20-year results using three different calculations, and in aggregate, 23 of 27 scenarios show net customer benefits with an average present-value net benefit of $227 million.

Q. Ms. Kelly does a similar calculation and concludes that the benefits in each price-policy scenario drop by $77 million. (Kelly Response Testimony, lines 227–236.) How do you respond?

A. Ms. Kelly did not supply work papers with her testimony, so I was not able to identify why her estimated impact of applying nominal capital revenue requirement in the 20-year studies differs from Mr. Hayet's estimates. The company's treatment of PTCs and capital revenue requirement appropriately accounts for the front-loaded PTC benefits without overstating capital revenue requirement, which extends beyond the 20-year time frame simulated with the IRP models. Nonetheless, Ms. Kelly's analysis similarly shows that, based on her calculations, the Combined Projects are expected to produce net customer benefits in seven of nine price-policy scenarios.

Q. Mr. Mullins concludes that while PacifiCorp's new modeling approach ensures that the entirety of PTC benefits will be captured in the 20-year economic evaluation, some of the transmission and other capital-related revenue requirements will be excluded from that 20-year analysis. (Mullins Supplemental Rebuttal, lines 455–468.) Do you agree?

A. Yes. In fact, and as I discussed earlier, this is appropriate when using the SO model, which simulates PacifiCorp's system through 2036, to select among different bids offered under different commercial structures. In the 20-year IRP analysis, application of nominal PTC benefits and levelized capital revenue requirement appropriately reflects the relative difference in the present-value benefits and costs from a resource portfolio that includes the Combined Projects with a resource portfolio that does not include the Combined Projects. Interestingly, in asserting that certain costs are not captured in PacifiCorp's 20-year IRP analysis, Mr. Mullins fails to mention that this analysis also does not capture any benefits that the Combined Projects will generate beyond the 20-year time frame.

Q. Mr. Hayet asserts that through the nominal treatment of PTCs and levelized treatment of capital costs, the company maximized the inclusion of PTC benefits but minimized the inclusion of capital revenue requirements in its economic analysis, thereby increasing the benefits of each project. (Hayet Second Rebuttal, lines 258–359.) Is this accurate?

A. No. As discussed above, PacifiCorp's approach to calculating the change in present-value system costs between resource portfolios with and without the Combined Projects in the 20-year IRP analysis is appropriate. It is only appropriate to include capital revenue requirement on a nominal basis in present-value calculations when those calculations cover the full life of the proposed wind facilities. That conservative analysis, including Uinta, is included in my supplemental direct testimony, and without Uinta, is summarized earlier in this surrebuttal testimony. The analyses demonstrate that the Combined Projects are expected to generate net customer benefits in seven of nine price-policy scenarios before considering upside benefits from potential renewable-energy credit ("RECs") revenues, operations and maintenance ("O&M") cost savings, application of less conservative system benefit assumptions beyond 2036, an approximately 200 MW increase in transfer capability across the Aeolus-to-Bridger/Anticline transmission line, and application of Aeolus-to-Bridger/Anticline transmission costs in base case simulations without the proposed new wind projects.

Q. Mr. Mullins applies certain modeling adjustments that more than eliminate the $167 million in net benefits projected in the company's nominal revenue requirement analysis economic analysis through 2050 (including Uinta). Are these adjustments valid?

A. No. Mr. Mullins applies adjustments related to ongoing transmission capital, OATT transmission revenues, energy-imbalance market ("EIM") uninstructed imbalance costs, EIM transmission, and a reduction in market prices. I address each of these items in turn below.

Q. Mr. Mullins claims the company did not consider ongoing capital maintenance costs for the Transmission Projects, and that if these costs are considered it would reduce net benefits from the Combined Projects. (Mullins Supplemental Rebuttal, lines 482–511.) Do you agree?

A. No. Mr. Vail explains how Mr. Mullins mischaracterized PacifiCorp's response to UAE Data Request 5.4, and clarifies that the company does not expect an increase to overall capital maintenance costs, let alone run-rate capital expenditures that equate to 100 percent of the initial investment. Moreover, even if total system run-rate capital expenditures were to increase after the Aeolus-to-Bridger/Anticline line is placed in service, it would not be appropriate to include the impact of these costs beyond 2050, which I understand is what Mr. Mullins refers to as the "terminal period." This approach inappropriately assigns costs without consideration of offsetting benefits from the new transmission line that will persist well beyond 2050. Consequently, Mr. Mullins's adjustments related to ongoing capital expenditures for the Aeolus-to-Bridger/Anticline transmission line are not valid and should be rejected.

Q. Mr. Mullins claims the company has applied faulty assumptions for incremental transmission revenue credits. (Mullins Supplemental Rebuttal, lines 600–670.) Mr. Peaco also questions the company's transmission revenue assumptions. (Peaco Supplemental Rebuttal and Surrebuttal, lines 401–410.) How do you respond?

A. Mr. Vail explains that transmission costs are allocated among transmission customers based primarily on load, that Mr. Mullins misunderstands how transmission rates are calculated, and that PacifiCorp's incremental transmission revenue credit assumptions are conservative, not high.

In addition, Mr. Mullins's calculations are wrong. Mr. Mullins takes a $72 million dollar benefit from the transmission revenue credits, which is 12 percent of the $602 million present-value cost (calculated off of nominal revenue requirement cost through 2050) and reduces it by 0.38 percent to 11.62 percent. Mr. Mullins then applies this change in percentage to the total annual transmission revenue requirement instead of the transmission revenue requirement associated with just the Aeolus-to-Bridger/Anticline transmission line. Transmission revenue requirement that is not associated with the Aeolus-to-Bridger/Anticline transmission line would change with changes to the percentage of costs paid by third-party transmission customers regardless of whether this line is included in rate base. If one were to assume an alternative percentage, it would only apply to the incremental cost of the Aeolus-to-Bridger/Anticline transmission line. Correcting Mr. Mullins's error would reduce his calculated adjustment, which is not necessary to begin with, from $25.7 million to $2.3 million. Mr. Mullins's adjustments related to OATT transmission revenues are not necessary, calculated in error, and should be rejected.

Mr. Peaco takes his criticism of OATT transmission revenues to the extreme, and calculates revised net benefit results that completely eliminate these benefits because he believes they are speculative and highly uncertain. (Peaco Supplemental Rebuttal and Surrebuttal, lines 811-823). As noted by Mr. Vail, transmission revenues are not speculative and highly uncertain, and if anything, the company's assumptions are conservative. Consequently, Mr. Peaco’s adjustment for OATT transmission revenues is unnecessary, not supported, and should be rejected.

Q. Mr. Mullins again argues that the Company has not accounted for energy EIM uninstructed imbalance charges. (Mullins Supplemental Rebuttal, lines 719–724.) Can you please explain uninstructed imbalance charges?

A. Yes. First, I will provide more context for the explanation and describe how EIM settlements are calculated for PacifiCorp’s resources. In the EIM, the company provides a base schedule for all of its participating and non-participating resources, including variable energy resources such as wind facilities. The base schedules are hourly and are used by the California Independent System Operator (“CAISO”) for purposes of a balancing test to ensure that the company has scheduled its resources within one percent of its expected demand in the upcoming hour. The next step in the scheduling process is the 15-minute schedule, which is generated approximately 30 minutes before the operating interval for each resource in PacifiCorp's system. This fifteen-minute schedule is considered an advisory schedule because it is not used for dispatch purposes. Finally, there is a five-minute schedule, which is a dispatch instruction to each of PacifiCorp’s resources, including expected wind output for the five-minute interval. Each of these three schedules—hourly, 15-minute and five-minute—is used to calculate the instructed imbalance market settlements for a resource.

For the uninstructed imbalance settlement, the CAISO uses the variance in the actual submitted meter data for a resource, the five-minute dispatch instruction, and the five-minute locational marginal price at the resource node. The difference between the five-minute dispatch instruction and the actual meter data is multiplied by the locational marginal price and divided by 12 (division by 12 is required because the time frame is a five-minute interval, and there are 12 five-minute intervals in an hour). This calculation results in a charge to a resource if it produced less energy relative to the schedule. Conversely, this calculation results in a payment to a resource if it produced more energy relative to its schedule.

Q. In the company's supplemental direct and rebuttal filing, Mr. Vail testified that the company expects that the uninstructed imbalance charges should be neutral over the life of the resource. (Vail Supplemental Direct and Rebuttal, lines 711–728.) Mr. Mullins argues that Mr. Vail was wrong. (Mullins Supplemental Rebuttal, lines 725–736.) How do you respond?

A. As explained by Mr. Vail, the uninstructed imbalance charges are a reflection of forecast error (actual meter data minus a five-minute forecast). Assuming that the forecast, which is produced less than 30 minutes before the interval, has an equal chance of being higher or lower over the life of a resource, the net charges should be close to zero.

Mr. Mullins provides evidence related to two resources over a short period of time to argue that there is an inherent bias in the forecasting. But the alleged bias is simply the result of Mr. Mullins's reliance on a limited data set and is not reflective of long-term expectations, which are that the net outcome will be closer to zero.

Q. Are there any other flaws in Mr. Mullins's analysis?

A. Yes. The existence of uninstructed imbalance charges assigned to certain resources does not mean that there is an actual cost (or revenue) that is passed through to customers. Uninstructed imbalance reflects the movement of resources and load that are outside of the CAISO's dispatch, and PacifiCorp is therefore required to manage that variation using its regulating resources as the balancing area authority. PacifiCorp must manage its area-control error as close to zero as possible to maintain its balancing and frequency requirements in accordance with the National Electric Reliability Council's standards. Thus, if a wind resource was five MW above its CAISO dispatch (five-minute forecast), then another resource, likely a regulating resource, on the PacifiCorp system would need to decrease by five MW to maintain system balance.

Q. When the regulating resource moves in the opposite direction of the wind resource, is that considered uninstructed imbalance?

A. Yes. The movement would be uninstructed imbalance because it was not part of the CAISO's dispatch solution. When PacifiCorp regulates with its resources for changes in wind, solar, and load outside of the CAISO's dispatch, that is considered regulation and is maintained by keeping several of PacifiCorp thermal units in "regulating mode" to make sure that PacifiCorp's system-balancing requirements are met.

Q. Does that mean there is a reciprocal cost or revenue for PacifiCorp's regulating resources?

A. Yes. While Mr. Mullins includes a table that shows a cost for the wind facilities' uninstructed imbalance, what he does not show is the corresponding revenue that was received by one of PacifiCorp's regulating resources.

Q. Is there a cost for regulating for variable-energy resources?

A. Yes. There is a cost for regulating for variable-energy resources, which is why PacifiCorp includes an integration cost in its economic analysis, consistent with the company's application of an integration cost in the IRP.

Q. If the Commission used Mr. Mullins's assessment of the uninstructed imbalance costs for the new wind facilities, would that be double counting the costs of integration?

A. Yes. As noted above, integration costs are already included in the company's economic analysis. Mr. Mullins's adjustment for EIM uninstructed imbalance charges is based on a limited data set that ignores expected long term trends, ignores offsetting revenues from regulating resources, and, as noted, double counts the cost of wind integration already factored into the company's economic analysis. Consequently, Mr. Mullins's EIM uninstructed energy imbalance adjustment should be rejected.

Q. Mr. Mullins also claims that PacifiCorp improperly considered EIM benefits by assuming there is a 300 MW transmission connection between the company's east and west balancing authority areas. (Mullins Supplemental Rebuttal, lines 673–710.) How do you respond?

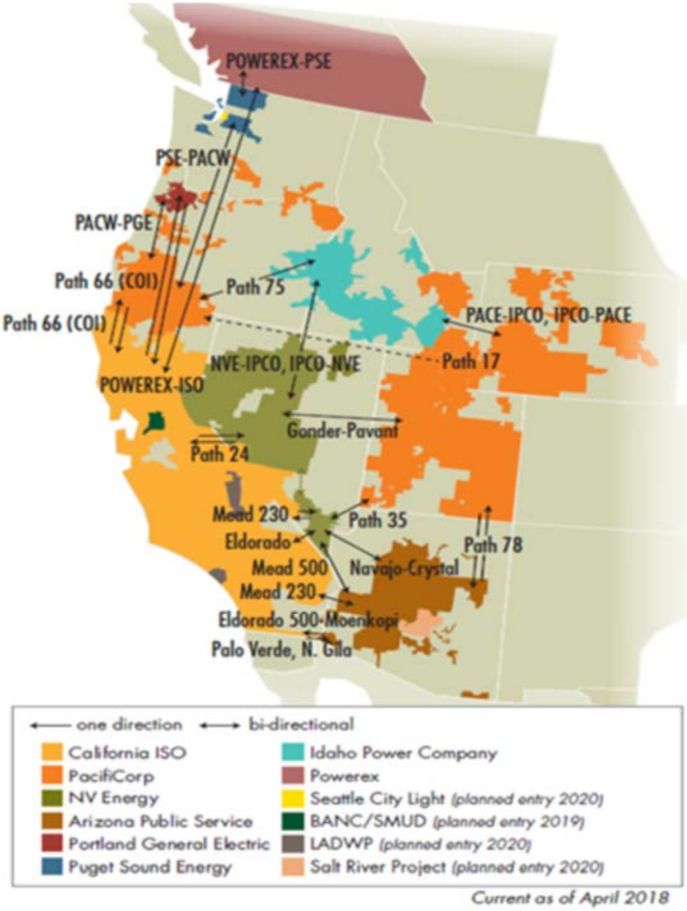
A. As described in my direct testimony, unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour, and there will be more efficient use of transmission with growing participation in the EIM. This was captured in the company's economic analysis by increasing the transfer capability between the east and west side of PacifiCorp's system by 300 MW. (Link Direct, lines 576–591.) Mr. Mullins states that this new transmission link does not exist today and testifies that PacifiCorp has no plans to build new transmission that would provide this increase in transfer capability. (Mullins Supplemental Rebuttal, lines 679–680.)

Mr. Mullins continues to misunderstand the incremental EIM transfer assumptions applied in the company's economic analysis. At no point has the company claimed that a new transmission line would be required to facilitate incremental intra-hour transfers between its east and west balancing authority areas. This incremental transfer capability results from intra-hour availability of unscheduled, unused, or re-optimized *existing* transmission. As more entities that have transmission connections with PacifiCorp's system join the EIM, there are increased opportunities to optimize these transmission assets within the hour. Despite Mr. Mullins's claims to the contrary, the EIM does in fact optimize the use of transmission assets of participating EIM entities within the hour. And this increased connectivity between PacifiCorp and other EIM entities currently enables additional transfers between the company's east and west balancing authority areas.

Figure 1-SR shows existing EIM entities and their transmission transfer capability. This figures shows a large amount of transfer capability between PacifiCorp's east balancing authority area Idaho Power, Nevada Energy, and Arizona Public Service Company. The transfer capability between Idaho Power and PacifiCorp's west balancing authority area is 1,500 MW (note, the transfer capability from PacifiCorp's east balancing authority area to Idaho Power is 2,557 MW).

PacifiCorp's EIM transfer assumptions are conservative in light of the total available transfer capability from PacifiCorp's east balancing authority area to its west balancing authority area through Idaho Power's system. Mr. Mullins's proposed adjustment for increased EIM transfers is based on a misunderstanding of the company's assumptions and should be rejected.

Figure 1-SR: Transfer Capability of Existing EIM Entities



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400* **
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <–> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <–> PSE	150
Powerex <–> ISO	150

** Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity.*

*** When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17, and not double counted.*

Q. Mr. Mullins also recommends an adjustment based on his allegation that PacifiCorp's economic analysis has not taken into consideration declining market prices. (Mullins Supplemental Rebuttal, lines 534–542.) And Mr. Peaco continues to believe the company's natural gas price assumptions are overstated. (Peaco Supplemental Rebuttal and Surrebuttal, lines 1222–1230.) Do you agree with these allegations?

A. No. Mr. Mullins correctly notes that PacifiCorp's December 2017 official forward price curve ("OFPC") reflects 72 months of market forwards followed by 12 months of a forwards-fundamental blend that transitions to a pure fundamentals-based forecast in month 85. Consequently, the first seven years of the December 2017 OFPC reflects or is influenced by observed market forwards as of December 29, 2017. This was the most current OFPC available at the time the company was finalizing its 2017R RFP bid evaluation and selection process and is representative of current market conditions.

Q. How is PacifiCorp's long-term natural gas price formulated?

A. PacifiCorp's natural gas price forecast reflects projections from an expert third-party forecasting service. The company subscribes to two expert third-party forecasting services to receive multi-client "off-the-shelf" natural gas-price forecasts, with supporting data, on a regular basis. Both forecasting services employ experts that perform energy market research and analytics to support hundreds of clients.

PacifiCorp's base case (medium) forecast provided by one of these third-party forecasting services is a moderate and reasonable long-term view supported by market research, analytics, and market fundamentals, as we know them today. Consequently, PacifiCorp's base case OFPC reflects observed forward market prices and a balanced, mainstream view of longer-term price projections.

Q. In their criticisms of PacifiCorp's market-price assumptions, do Mr. Mullins or any of the other parties address the material drivers for their expectations regarding long-term market prices?

A. No. Their analysis is based on past trends without addressing the likely drivers of price change.

Q. Can natural gas prices keep going down?

A. Not forever. For a decade now, natural gas prices have continued to reflect the effects of technological progress and increased producer efficiencies in expanding the resource base while lowering break-even costs. Between Appalachia and associated gas, supply is expected to outpace demand for the next five to six years, but diminishing returns (and as a corollary rising costs) will not be outpaced by technological progress and producer efficiencies forever. Drilling efficiency improvements continue but at a slower pace than in prior years and increased demands will require more expensive take-away capacity to be built out of Appalachia and the Permian. Thus, price appreciation is expected to take hold around the 2024-2025 time frame. Moreover, Appalachia and associated gas volumes (the lowest cost supplies) are expected to flatten after 2024, which is when liquefied natural gas ("LNG") exports and power sector demands are expected to accelerate.

Also, as noted by Ms. Kelly, "prices are closer to a floor than to a ceiling… the risk of lower and higher gas prices is asymmetrical. If gas prices are predicted to be $3.00, they can only be, at most, $3.00 too high. On the other hand, the upside of the equation is boundless. Prices in the past have reached $12.00 or more." (Kelly Response, lines 291–305.) Trends typically bottom-out and eventually end. Expert forecasts, based on comprehensive research and fundamentals-based market analysis account for changes in market dynamics that are not captured by evaluating past price trends.

Q. Why is demand for natural gas expected to grow in the 2024-2025 time frame?

PacifiCorp's nominal Henry Hub price forecast does not exceed $4.00/MMBtu until 2025 (2034 in 2016 dollars). Natural gas markets have historically been local due to transportation constraints, but the liquefaction of natural gas has linked domestic supplies to the global market, and this linkage will increase with growing LNG exports. Significant growth in LNG demand is coming from Asia, Europe, South America, and

Mexico. Moreover, piped exports into Mexico are expected to grow by 2025. In just a few years, U.S. LNG exports have gone from zero to six billion-cubic-feet (“BCF”) per day, and U.S. LNG exports are expected to rise to between nine and 12 BCF per day by 2025.

Q. Mr. Mullins goes on to explain that the company relies on a third-party forecast from November 21, 2017, and is concerned that the December 2017 OFPC does not consider the effects of tax reform. (Mullins Supplemental Rebuttal, lines 557–565.) How do you respond?

A. As noted above, the OFPC reflects or is influenced by observed market prices through the first seven years (through 2024). The December 2017 OFPC that the company used in its medium price-policy scenarios reflects market forwards as of December 29, 2017, which is *after* President Trump signed the tax reform bill. This means that through the first seven years of the December 2017 OFPC, observed prices account for tax reform. Moreover, I have reviewed observed forward prices, which are updated each trading day, throughout December 2017, and there is no indication that there was any material change in forward prices that coincided with the timing of when tax reform legislation was passed by Congress and subsequently signed by President Trump. Consequently, I would not expect a material change in forecasted prices beyond the first seven years of the December 2017 OFPC.

Q. Did Mr. Mullins present all of the natural gas price forecasts he received from the company through discovery in Confidential Figure 3 of his supplemental rebuttal testimony?

A. No. PacifiCorp also provided an update to the November 2017 natural gas price forecast that was used in the company's December 2017 OFPC. This updated forecast was issued on February 18, 2018 and is actually slightly *higher* than the November 2017 forecast used in the company's economic analysis. However, Mr. Mullins chose to omit this forecast in Confidential Figure 3 of his supplemental rebuttal testimony.

Q. Mr. Mullins testifies that market prices are declining, and he estimates that if a more recent price forecast were used, net benefits projected in the company's economic analysis would decline. (Mullins Supplemental Rebuttal, lines 580–593.) How do you respond?

A. I am not surprised that net benefits from the Combined Projects would be reduced when applying a lower natural gas-price assumption—this is consistent with the company's economic analysis which shows reduced benefits in low natural gas-price scenarios. As noted above, Mr. Mullins omitted from his analysis other, more current, third-party projections that are higher than those used in the company's economic analysis. Had Mr. Mullins chosen to estimate how this forecast affects customer benefits, I would anticipate it would show increased benefits relative to the company's base case analysis. Mr. Mullins is simply reconfirming that market price assumptions are a variable that will influence overall customer benefits from the Combined Projects.

While Mr. Mullins is entitled to his view of long-term market prices, I remain confident that PacifiCorp's OFPC, which is based on observed market forwards and third-party forecasts supported by market research and informed by current market fundamentals, is the best and most likely forecast. This is the same forecast used to set customer rates and to establish avoided-cost prices for qualifying facilities. Nonetheless, even if market prices were to move, on a sustained basis, to those levels assumed by Mr. Mullins, the Combined Projects would still produce present-value net benefits for customers.

Q. Mr. Peaco claims that the "Combined Projects appear less likely to provide benefits to customers in the Low Gas scenarios and provide no meaningful improvement in the Medium and High Gas scenarios." (Peaco Supplemental Rebuttal and Surrebuttal, lines 666–668.) Do you agree?

A. No. Mr. Peaco's conclusion requires a wholesale rejection of PacifiCorp's economic analysis, which continues to show that customer benefits are highly likely. Contrary to Mr. Peaco's claims, customer benefits grow appreciably with higher natural gas price assumptions. Moreover, and as I stated earlier, the company's economic analysis is conservative. Mr. Peaco's assertion that benefits in the company's 20-year economic analysis are inflated due to the nominal treatment of PTCs, which was necessary to select among wind bids offered under different commercial structures in the 2017R RFP, is refuted in my testimony above.

Q. Mr. Peaco calculates a cost-benefit ratio of the Combined Projects across the nine price-policy scenarios in Table 1 of his supplemental rebuttal testimony and concludes that there are limited benefits relative to costs. (Peaco Surrebuttal, lines 443–473.) How do you respond?

A. Mr. Peaco calculates a simplified cost-benefit ratio in which a cost-benefit ratio greater than one indicates that benefits exceed costs, and a cost-benefit ratio less than one indicates that costs exceed benefits. In the medium natural gas, medium CO_2 price-policy scenario, the most likely outcome, Mr. Peaco's high-level analysis shows a positive cost-benefit ratio. Only in the low natural gas, zero CO_2 price-policy scenario, a scenario that Mr. Peaco has clarified is not the most likely scenario, and low natural gas, medium CO_2 price-policy scenario, are Mr. Peaco's cost-benefit ratios less than one.

Q. What conclusions do you draw from Mr. Peaco's cost-benefit analysis?

A. Mr. Peaco's cost-benefit analysis validates that PacifiCorp's economic analysis is reasonable. Consistent with my findings, Mr. Peaco's independent and high-level cost-benefit analysis shows net customer benefits in seven of nine price-policy scenarios, and that upside benefits outweigh downside risks. And despite Mr. Peaco's claims that the company's analysis overstates customer benefits, the company's economic analysis is conservative, because it does not account for potential Renewable Energy Credits ("REC") revenues, O&M cost savings, application of less conservative system benefit assumptions beyond 2036, an approximately 200 MW increase in transfer capability across the Aeolus-to-Bridger/Anticline transmission line, and application of Aeolus-to-Bridger/Anticline transmission costs in base case simulations without the proposed new wind projects. When averaged among all nine price policy scenarios, Mr. Peaco's cost-benefit ratios average over 1.092, meaning that on average, benefits outweigh costs by approximately 9.2 percent.

As noted above, in a previous request for approval of a voluntary resource decision filed by the company, DPU used this approach to evaluate the economics of the resource decision because, according to DPU's expert witness in that case, using the simple average of the price-policy scenario results produced a reasonable "risk-weighted benefit" that assumes each of the price-policy results is "equally likely." *In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval* *of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4*, Docket No. 12-035-92, DPU Exhibit 2.0 SR, lines 52–58 (Feb. 28, 2013). DPU's expert explained that using a simple average to produce a risk-weighted benefit was a "pretty good way" to do it because it was "neutral" and "doesn't attempt to say that lower gas prices are more likely or less likely in the future, just that they are equally likely with the base and high gas price forecasts." *In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4*, Docket No. 12-035-92, Transcript, page 165, lines 1–10 (Mar. 7, 2013).

Q. Mr. Peaco claims that his objections to the company's extrapolation methodology are unrefuted. (Peaco, Supplemental Rebuttal and Surrebuttal, lines 443–473.) Do you agree?

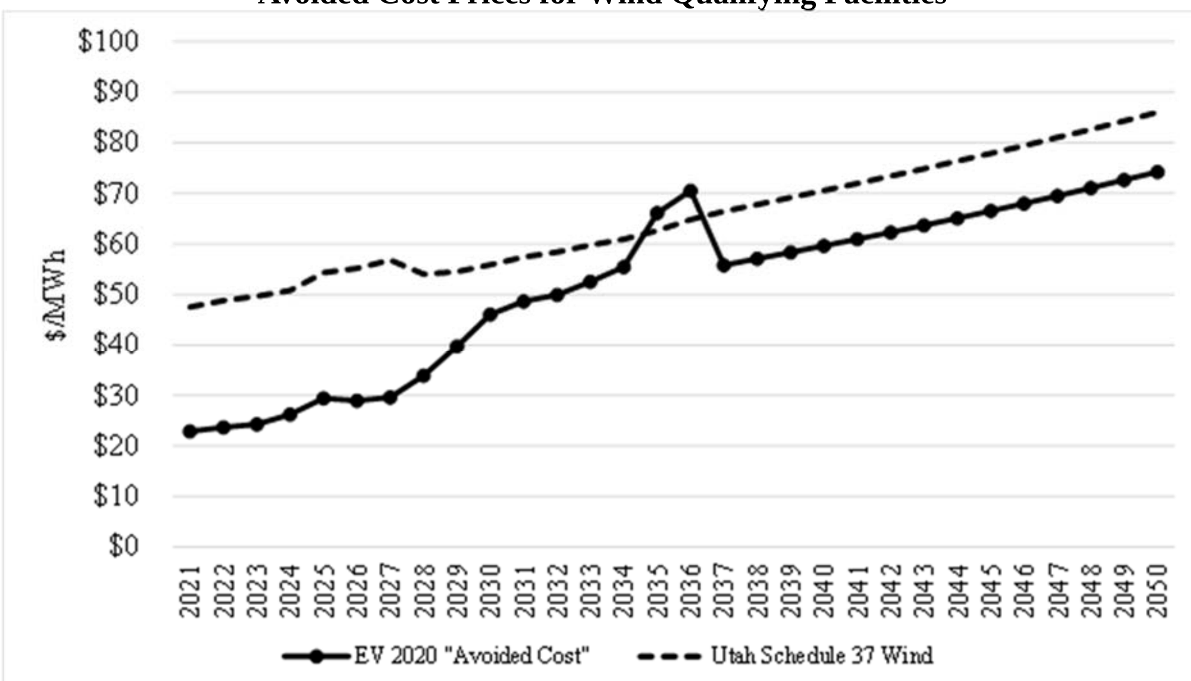
A. No. In my supplemental direct and rebuttal testimony, I responded to Mr. Peaco's criticisms, noting that he simply stated the company's results were problematic without adequately describing what those "problematic results" were. I also emphasized why the company's approach, which is based on a projection of how the Combined Projects are forecasted to affect system costs, is reasonable. (Link Supplemental Direct and Rebuttal, lines 1404–1416.) Mr. Peaco references specific examples of concerns he raised related to the company's extrapolation methodology in Docket No. 17-035-39. However, consistent with my supplemental direct and rebuttal testimony, he has not adequately identified the alleged anomalous results specific to the economic analysis in this proceeding that he states is the source of his concern. Further, in my second supplemental testimony, I explain why the company's extrapolated results are actually conservative when compared to the results observed from the models. (Link Second Supplemental Direct, lines 396–403.)

Q. In addition to comparing the extrapolated benefits to the benefits reported by the model in 2036, are there any other comparisons you can make that show the company's extrapolation approach is conservative?

A. Yes. PacifiCorp's economic analysis calculates the change in system costs between two model simulations—one with and one without the Combined Projects. This is precisely the same concept that is used to develop avoided cost prices for qualifying facility projects in Utah. Figure 2-SR compares the system benefits from the Combined Projects (without Uinta) on a dollar-per-MWh basis to the currently effective Utah Schedule 37 avoided-cost price for wind qualifying facilities. The currently effective avoided-cost price, which is meant to represent the value to PacifiCorp of purchasing energy and capacity from a wind qualifying facility, is available through 2036. Consistent with Utah Commission's order in Docket Nos. 17-035-T07 and 17-035-37, I extended the Utah Schedule 37 avoided cost price beyond 2036 at inflation so that it can be compared to the extrapolated system benefits used in the company's nominal revenue-requirement economic analysis.

The figure not only highlights my earlier point that the company's extrapolated benefits beyond 2036 do not reach the levels observed in the model in 2036 until about 2047, it also shows that the extrapolated benefits are significantly lower than the projected value of wind from a qualifying facility. In fact, the company's economic analysis also reflects estimated economic benefits that are also significantly lower than the Utah Schedule 37 avoided-cost price for wind in the near term. The levelized value of a Utah Schedule 37 wind facility over the 2021-2050 time frame is $59.12/MWh. Over this same period, the levelized value of the Combined Projects in the company's economic analysis is $42.69/MWh. If the Utah Schedule 37 avoided cost price for wind were used in lieu of the company's projected system benefits, the PVRR(d) benefits from the Combined Projects (without Uinta) in the medium case would increase from $174 million to $435 million when assessed through 2050.

Figure 2-SR: System Benefits Relative to Utah Schedule 37 Avoided Cost Prices for Wind Qualifying Facilities



Q. Mr. Mullins contends that there is a mismatch between nominal and levelized results, invalidating the 20-year study period analysis. He further states that the nominal study is a more straight-forward approach. (Mullins, Supplemental Rebuttal, lines 451–454.) 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, 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 application for approval 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 PVRR(d) to be calculated, as with any long-term study, longer-term results are increasingly more difficult to project. Moreover, as noted above, I explained 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. Peaco claims that economic benefits from the Combined Projects have declined relative to Direct Testimony. (Peaco Supplemental Rebuttal, lines 610–654.) Do you agree?

A. No. Based on Mr. Peaco’s own tables, customer benefits have increased in the majority of cases, and by greater margins than decreases in the remaining cases. For instance, in Table 3 of Mr. Peaco’s rebuttal testimony, the 30-year expected case reports increased benefits of $30 million relative to the company’s direct filing. 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 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.

Q. Mr. Peaco and Mr. Hayet disagree with application of a terminal value benefit in 2050, claiming that such a benefit is speculative and was not included in the original analysis. (Peaco Supplemental Rebuttal and Surrebuttal, lines 749–756; Hayet Second Rebuttal, lines 467–490.) 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 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 (without Uinta) would still produce $136 million in net customer benefits in the medium case before accounting for all of the conservative assumptions used in the company's economic analysis. In its initial filing, which relied upon proxy resources before the 2017R RFP was issued and when it was uncertain whether the company would own and operate winning bids, the company's economic analysis conservatively did not account for terminal value. However, the 2017R RFP specifically identified that terminal value would be considered during the bid evaluation and selection process, and once the winning bids were identified, these benefits, where applicable, were included in the company's economic analysis.

Q. Mr. Peaco suggests that terminal value benefits should be removed when calculating his alternative net benefits estimates. (Peaco Supplemental Rebuttal and Surrebuttal, lines 811–823.) How do you respond?

A. In Table 6 of Mr. Peaco's rebuttal testimony, he eliminates terminal value benefits. In making this adjustment, Mr. Peaco assumes that interconnection transmission assets, land rights, development rights, and other assets that have lives that extend beyond the assumed 30-year life of a wind facility, including retained access to a high-quality wind resource, will have no value. This is inappropriate, and his adjustment should be rejected.

Q. Mr. Mullins challenges the terminal value used in the company's economic analysis and suggests that transmission costs beyond 2050 should be included in the nominal revenue requirement analysis. (Mullins Supplemental Rebuttal, lines 475–493.) Mr. Peaco similarly recommends adjustments to add transmission costs beyond 2050. (Peaco Supplemental Rebuttal and Surrebuttal, lines 811–823.) Do you agree?

A. No. While Mr. Mullins does not challenge the magnitude of terminal values associated with the new wind projects, and does "not necessarily disagree" that utility-owned resources provide a terminal value that PPAs do not, he argues that, with regard to the transmission project, the company needed to also consider the ongoing capital maintenance and investment required to achieve the terminal value assumed in the economic analysis.

PacifiCorp's analysis recognizes that the useful life of the transmission project extends more than 30 years beyond the useful life of the new wind projects. Mr. Mullins and Mr. Peaco are correct that costs of the transmission project are not included beyond 2036 in the system modeling, nor are they included beyond 2050 in the nominal revenue requirement analyses. However, as noted in my testimony above, the company also did not include any incremental benefits of the proposed transmission project beyond 2036 in the levelized view, or beyond 2050 in the nominal view.

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

A. The terminal value benefit recognizes the fact that at the 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. Mr. Hayet asserts that PacifiCorp's assessment of terminal value is speculative and based on the assumption that new generation is built at the same project sites (Hayet Second Rebuttal, lines 172–175, 467–490.) How do you respond?

A. Terminal value, as assessed and described by PacifiCorp, includes: development rights; transmission assets (*e.g.*, network upgrades); and non-transmission infrastructure (*e.g.*, roads). PacifiCorp's terminal value reflects the material difference in the end-of-life worth of owned assets relative to PPA structures, and it is reasonable to expect that reasonable infrastructure value is expected to remain once these wind facilities have reached the end of their operating life. As discussed below, the independent evaluators confirmed the reasonability of this position and the conservative values used by PacifiCorp.

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

A. Yes. The Utah independent evaluator 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 independent evaluator 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 independent evaluator 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 independent evaluators comment on the size of the terminal value benefit?

A. Yes. The Utah independent evaluator noted that the terminal value was "relatively low." (Utah IE Report at 42.) Likewise, the Oregon independent evaluator found that the "terminal value adders were fairly small." (Oregon IE Report at 17.) Notably, both of the independent evaluators confirmed and validated the company's bid selection and evaluation process, and proposed no adjustment.

THE PROCESS HAS ALLOWED FOR ROBUST REVIEW OF THE COMBINED PROJECTS

Q. Dr. Zenger claims that the IRP results for the Combined Projects and repowering were not filed until five months after filing the 2017 IRP. (Zenger Supplemental Rebuttal and Surrebuttal, lines 179–185.) Is this accurate?

A. No. PacifiCorp filed its 2017 IRP on April 4, 2017, which included economic analysis of the Combined Projects and repowering. PacifiCorp made an informational filing on August 2, 2017, a little less than four months after filing the 2017 IRP, which provided an updated economic analysis supporting the wind repowering, new transmission, and new wind investments. This informational filing summarized the very economic analysis that was included in the company's June 30, 2017 application and presented in my direct testimony. This informational filing was made to ensure that all IRP stakeholders, including those stakeholders that are not participating in this proceeding, had access to the most current economic analysis supporting the wind repowering, new transmission, and new wind investments contained in the 2017 IRP preferred portfolio.

Dr. Zenger's claim that parties have not had an opportunity to provide meaningful input is contrary to the facts. In February 2017, PacifiCorp finalized its IRP analysis of the Combined Projects. The scope of the Combined Projects and the accompanying economic analysis was discussed at a public-input meeting held in early March 2017, before filing the 2017 IRP on April 4, 2017. Moreover, after the 2017 IRP was filed, and before the application for the Combined Projects was filed, PacifiCorp met with IRP stakeholders to discuss the Combined Projects. The meeting with DPU took place May 10, 2017. Parties have had ample opportunity to review the Combined Projects since the 2017 IRP was filed over one year ago and have been reviewing the robust economic analysis presented in this proceeding for nearly 11 months.

Q. Dr. Zenger states: "Rather than representing refinements of a well-vetted structure for forecasting the future, the most recent projections in this Combined Projects docket result from shifting assumptions and structures following each round of review by non-company parties." (Zenger Supplemental Rebuttal and Surrebuttal, lines 168–178.) How do you respond?

A. I disagree. PacifiCorp has appropriately updated its assumptions and projections to ensure that its economic analysis remains current and that the results of this analysis accurately reflect projected customer benefits. These updates were necessary to confirm that the Combined Projects will deliver customer benefits, despite changes to federal tax law and market forces that are beyond PacifiCorp's control. To facilitate the parties' review of PacifiCorp's filings, the company has been transparent, has thoroughly documented and explained its updated assumptions, and has provided extensive work papers that support all of the economic analyses presented in testimony and accompanying exhibits.

Q. Dr. Zenger also states that evolving project details and updates to costs and benefits indicate that the Combined Projects are "uncertain enough to suggest preapproval is not in the public interest." (Zenger Supplemental Rebuttal and Surrebuttal, lines 108–122, 127–141.) Do you agree?

A. Absolutely not. As noted above, PacifiCorp has necessarily updated assumptions and projections to ensure its economic analysis of the projects remains current. This included updates to cost-and-performance inputs to align with bids received in the 2017R RFP, updates to reflect changes in federal tax law, updates to reflect more current load forecast and market forecast data, and a more accurate representation of PTCs. Through every step of the process, the economic analysis has shown that the proposed new wind and transmission investments are most likely to provide substantial customer benefits. Contrary to Dr. Zenger's opinion, the facts in this case demonstrate that the net benefits of the Combined Projects have withstood significant stress testing, which has only confirmed that Combined Projects will lower customer costs and are in the public interest.

Q. Dr. Zenger asserts that the process, including the expedited RFP, "burdened" parties to this docket. (Zenger Supplemental Rebuttal and Surrebuttal, lines 195–199). How do you respond?

A. Dr. Zenger's assertion is inconsistent with the testimony of DPU's witness addressing the RFP—Mr. Peterson. Mr. Peterson acknowledged the expedited schedule, but states: "In spite of a compressed schedule, the process worked fairly well." (Peterson Supplemental Rebuttal and Surrebuttal, line 150.) Also, the parties have had almost 11 months to review the Company's proposal, which is considerably longer than the timeframe provided by Utah statute.

PARTIES OVERSTATE PROJECT RISKS

Q. Dr. Zenger states that natural gas and carbon prices may be lower than assumed in the medium gas, medium CO_2 price-policy scenario, thus leading to an overstatement of benefits. (Zenger Supplemental Rebuttal and Surrebuttal, lines 337–342.) How do you respond?

A. PacifiCorp's medium gas, medium CO_2 price-policy scenario is the most reasonable and the most likely scenario that reflects observed forward market trades through 2024. Moreover, and as already noted in my rebuttal testimony, the low natural gas price forecast assumed stagnant LNG exports. 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. These increased exports will 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—and may actually be higher than current forecasting predicts. With natural gas prices already very low and future demands expected to ratchet up, market prices are likely to respond to upside pressures, especially over a 20-30 year period. Likewise, PacifiCorp's CO_2 assumptions are already modest and distant in implementation with the low case being zero, while the medium and high scenarios start at $4.49/ton in 2030 and $3.62/ton in 2026, respectively. Since the downside is bounded by zero, there is little room for meaningful CO_2 scenarios of a lesser magnitude than those assumed in PacifiCorp's economic analysis.

Q. Mr. Peaco clarifies that he has not testified that the low natural gas, zero CO_2 price-policy scenario is the most likely, but that his focus on this scenario is to establish an analytical basis for the "high likelihood of benefits" standard. (Peaco Supplemental Rebuttal and Surrebuttal, lines 306–322.) How do you respond?

A. Mr. Peaco asserts that the Commission should assess whether the Combined Projects are in the public interest by establishing a higher standard of review because he believes these projects are not needed and are being justified as an economic opportunity. As I stated earlier, the Company has never stated that the Combined Projects are not needed to reliably serve its customers. The Combined Projects provide an opportunity to meet the company's projected capacity deficit while delivering customer benefits. Consequently, I disagree with Mr. Peaco's argument that the Commission should review the Combined Projects under a higher standard.

My economic analysis has consistently shown that the Combined Projects are needed to reliably serve our customers and that these investments are *most likely* to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to retail customers in Utah. Despite the fact there is no need for the Commission to review these projects under a higher standard, my economic analysis shows that the Combined Projects also meet this higher standard and are *highly likely* to result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to retail customers in Utah. This economic analysis shows that the Combined Projects are expected to deliver net customer benefits in 16 of 18 modeled scenarios (nine price-policy scenarios over two different time frames). And these findings are conservative for the following reasons:

- Since the company's economic analysis was completed, updated transmission studies discussed by Mr. Rick A. Vail show the expected increase in transfer capability associated with the Aeolus-to-Bridger/Anticline transmission line is 951 MW, which is nearly 27 percent higher than the 750 MW assumed in the economic analysis.

- The economic analysis does not reflect expected O&M cost savings associated with installation of larger wind turbines at the TB Flats I & II and Ekola Flats projects.

- The economic analysis assigns no incremental value to the RECs that will be generated from the Combined Projects.

- The extrapolation of system benefits beyond 2036 are conservative as they do not reach levels observed in the model in 2036 until at least 2047.

- As described earlier in my testimony, the economic analysis conservatively assumes a base case simulation without any costs for the Aeolus-to-Bridger/Anticline transmission line—if this line were included in the base case simulation without the Combined Projects, it would increase present-value customer benefits by hundreds of millions of dollars in all price-policy scenarios.

- Price-policy scenarios that include a CO_2 price assumption are conservative because PacifiCorp inadvertently applied these inputs in 2012 dollars instead of nominal dollars.

Q. Mr. Peaco argues that there are scenarios is which the company may be correct in terms of benefits and there are scenarios in which the company may be wrong, concluding that the company is therefore asking customers to assume risks of large costs without corresponding benefits. (Peaco Supplemental Rebuttal and Surrebuttal, lines 361–365.) How do you respond?

A. I agree that there are market and policy uncertainties, which is why PacifiCorp analyzed a range of price-policy scenarios. When accounting for these uncertainties, PacifiCorp's economic analysis shows that not only are the Combined Projects *most likely* to generate net customer benefits relative to other resource options, they are *highly likely* to generate net customer benefits relative to other resource alternatives. My conservative analysis shows that this resource strategy would only be higher cost in two of 18 price-policy scenarios (nine price-policy scenarios and two different time frames). Moreover, Mr. Peaco has now clarified that one of these two scenarios—the low natural gas, zero CO_2 price-policy scenario—is not the most likely outcome (Peaco Supplemental Rebuttal and Surrebuttal, lines 309–311.)

Q. Are market risks greater for the Combined Project than for other resource options?

A. No. Market risk is inherent in every resource option, and most particularly FOTs, which are subject to fluctuations in market conditions right up to the moment of transaction. The zero-fuel-cost energy from the Wind Projects will reduce customer exposure to market risk, not increase customer exposure to market risk.

Q. Dr. Zenger states that moving forward with the Combined Projects may close off future opportunities for other possibly economic alternative resources such as battery storage or plant closures. (Zenger Supplemental Rebuttal and Surrebuttal, lines 357–361.) Do you agree?

A. No. This is a speculative claim that is entirely unsupported. PacifiCorp has evaluated all available resource options, including battery storage, plant closures, and transmission, under a range of market conditions and the Combined Projects are the most likely to deliver customer benefits. As I discussed earlier, even after PacifiCorp accounts for the incremental capacity from the Combined Projects, it has a remaining capacity shortfall that will require new resources to reliably serve our customers over time. PacifiCorp will continue to evaluate through each IRP cycle the least-cost, least-risk combination of resources that can be used to meet these capacity needs prospectively. The Combined Projects will not preclude PacifiCorp from evaluating all future resource alternatives, accounting for changes in technologies, system conditions, and market developments.

Q. Mr. Peaco claims that because the company took issue with his characterization of risk, such as production risk associated with the Wind Projects, that it is an example of the company asking customers to assume significant risk. (Peaco Supplemental Rebuttal and Surrebuttal, lines 323–336.) Is this true?

A. No. As I stated in my supplemental direct and rebuttal testimony, Mr. Peaco's analysis is asymmetrical and ignores the possibility that wind production may also be higher than reasonably assumed in my economic analysis. Mr. Peaco's assertion is not based on fact or analysis that supports his claim that the company is asking customers to assume significant wind-production risks. Simply stated, Mr. Peaco has not explained why he believes the company's wind production estimates are not reasonable. In contrast, PacifiCorp has 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.

Q. Is it your position that Mr. Peaco is overstating the P50-related wind variability risk?

A. Yes. Mr. Peaco's characterization of the P50 assessment and curtailment probability is extreme, and does not seem to consider principles of probability and outcome. The P50 assessment simply says that there is an equal probability of actual generation being higher or lower than the forecasted value. This does not mean that the company's wind shapes have a 50-percent chance of being completely wrong; it means rather that over time, statistics favor actual generation being high just as often as it is low, resulting in a long-term shape that closely matches the P50 shape. The reduction in P50 energy that Mr. Peaco refers to would therefore have to be a sustained and improbable reduction in wind generation, potentially lasting decades, and without offsetting seasonal or annual increases in wind.

Q. Does Mr. Peaco dispute the equally likely potential upside benefits related to wind variability?

A. No. While he mentions my earlier response to his unsupported criticisms of the company's wind-production estimates, he does not dispute it, and in fairness, I would assume he is concerned only with the potential for negative impacts to customers. To clarify my position, I do not believe that huge upside benefits will materialize any more than I believe Mr. Peaco's huge downside costs will occur. My point is only that the P50 wind shape is a carefully vetted and reasonable estimate, and that inevitable variations that occur will be offsetting over the long term.

Q. How has the level of risk for the Combined Projects changed since the initial filing?

A. While it is true that some changes have reduced customer benefits, decreases have been more than offset by other factors, such as lower installed capacity costs associated with the Wind Projects, which as I described earlier are down [redacted] percent relative to the cost for owned resources included in the company's initial filing.

Also, risks have been reduced because we now know much more about significant drivers of costs and benefits. 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 important 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. In total, when all of the changes are considered, and considering how much more we now know about tax policy and costs, the company's analysis shows that risks have decreased and customer benefits have increased since the initial filing.

Q. Dr. Zenger expresses concerns over changes to capital costs and argues that such large shifts can overwhelm benefits. (Zenger Supplemental Rebuttal and Surrebuttal, lines 238–247.) How do you respond?

A. Mr. Chad A. Teply rebuts the basis for Dr. Zenger's concerns over changes to capital costs, which have no bearing on whether actual costs will be higher or lower than current estimates. In fact, as stated above, the capital cost of owned wind facilities on a per-kilowatt basis is down [redacted] percent from the estimates assumed in the company's initial filing. As explained in my supplemental direct and rebuttal testimony, the reduction in capital costs has mitigated the reduction in benefits from changes in the federal income tax rate applicable to corporations. Dr. Zenger's claim that the large shift in capital costs can overwhelm benefits ignores my testimony, which demonstrates that benefits increased when the Ekola Flats project displaced PacifiCorp's McFadden Ridge II benchmark project even though capital costs also increased.

Q. Several parties also point to the comments made by the Oregon independent evaluator related to his recommendation to the Oregon Commission that the company's bids be subject to cost and performance guarantees to make the utility-owned resources comparable to PPAs. (*See, e.g.*, Peterson Supplemental Rebuttal and Surrebuttal, lines 289–311; Hayet Second Rebuttal, lines 999–1007.) How do you respond to the Oregon independent evaluator's recommendations?

A. As the Chair of the Oregon Commission pointed out during an April 30, 2018 special public meeting on the 2017R RFP final shortlist, the Oregon independent evaluator went beyond the scope of his responsibilities in opining on ratemaking considerations. The Chair highlighted that determining the future ratemaking treatment of the Wind Projects was the Oregon Commission’s responsibility (not the independent evaluator’s).

In addition, similar to the parties’ positions in this case, the Oregon independent evaluator’s ratemaking conditions were premised on the theory that there is no need for the Wind Projects. Because there is a clear need, the ratemaking conditions are irrelevant.

Q. Are all of the project risks raised by parties asymmetrical, meaning they would only harm customer interests?

A. No. The risks that parties have identified are really best characterized as uncertainties, and these uncertainties do not just provide downside risk for customers. These uncertainties also provide opportunities to improve customer benefits beyond what is assumed in PacifiCorp’s economic analysis. Project performance can be better than expected, as Mr. Chad A. Teply indicates has occurred. Capital costs can be lower than expected, as Mr. Vail indicates has occurred. Ongoing O&M costs can be less than expected, which is likely given the conservative assumptions used in the company’s economic analysis. Price and policy changes may increase the net benefits from the Combined Projects.

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 independent evaluators. The company also provided evidence that its prior two large-scale transmission projects were 19 percent and six percent under budget.

Q. How has PacifiCorp's ongoing analysis contributed to the assessment of risk?

A. PacifiCorp'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 new wind and transmission 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.

SOLAR RESOURCE SENSITIVITY

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

A. My supplemental direct testimony provided robust modeling results through 2036 using the SO model and PaR based on preliminary bid analysis from the 2017S RFP. Those modeling results supported two important conclusions.

First, solar PPAs provided fewer benefits than the Combined Projects under the medium natural gas, medium CO_2 price-policy scenario, and slightly fewer benefits under the low natural gas, zero CO_2 price-policy scenario using PaR, and slightly more benefits under the low natural gas, zero CO_2 price-policy scenario using the SO model. In other words, under the medium natural gas, medium CO_2 price-policy scenario, the Combined Projects are superior, and under the low natural gas, zero CO_2 price-policy 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 price-policy scenario and low natural gas, zero CO_2 price-policy scenario relative to scenarios where either the Combined Projects or solar PPAs are procured on their own.

Significantly, none of wind or solar bids were hard-coded into the model, and when solar bids were selected in the models, they did not displace the wind bids. 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 independent evaluators who monitored the 2017R RFP?

A. Yes. The Oregon independent evaluator 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 independent evaluator 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. Mullins argues that the solar sensitivity studies showed that the final bids received in the 2017S RFP were lower cost and lower risk than the Combined Projects. (Mullins Supplemental Rebuttal, lines 368–370.) 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 solar PPA bids do not displace the economic benefits of the Combined Project. While the base economic analyses of solar 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 in the base economic analysis 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 and through bi-lateral discussions with developers, 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, or if there is an opportunity to mitigate evaluation risks, there will be sufficient time to initiate a new competitive solicitation process or to pursue bi-lateral contracts 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 independent evaluator 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 independent evaluator retained by the company to monitor the 2017S RFP, on March 12, 2018. This summary is included in the final report of the independent evaluator for the 2017S RFP, which is provided as Exhibit RMP__(RTL-3SR) ("Solar IE Report").

Q. Did the independent evaluator for the 2017S RFP agree with the company's conclusions?

A. Yes. The independent evaluator concluded that the company's decision to not accept any solar bids was not unreasonable and that PacifiCorp's concerns over conditions in the solar market that reflected uncertainties over tax reform and tariffs were reasonable. In addition, the independent evaluator concluded that the 2017S RFP was conducted in a manner that was consistent with general procurement best practices, unbiased, that the selection of the shortlisted resources was fair, and that the company's modeling reflected industry best practices. (Solar IE Report at 4–5.)

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?

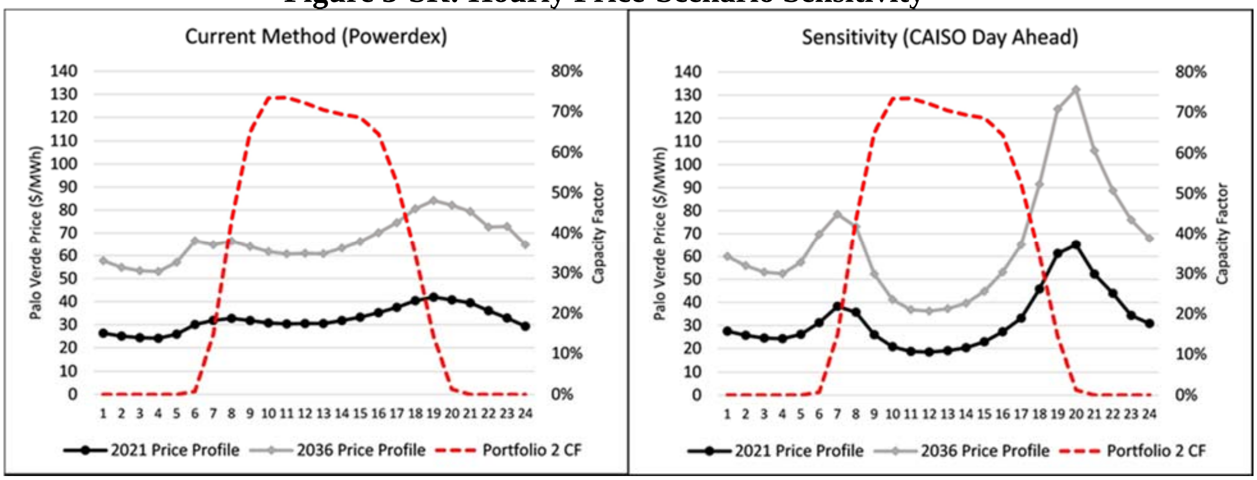
A. PacifiCorp performed two additional sensitivities. First, the company refined how it converts its forward market prices into hourly prices to more accurately reflect hourly market-price variation in those hours when solar resources are producing energy. Second, the company performed a capacity-contribution 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 prices 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 3-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 energy profile of bids included in a solar-PPA bid portfolio. The price profile used in the sensitivity shows that, when accounting for the growth of 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 used the refined scalars in the 2017 IRP Update and intends to continue using the refined scalars in future IRPs and future regulatory filings.

Q. How do 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.

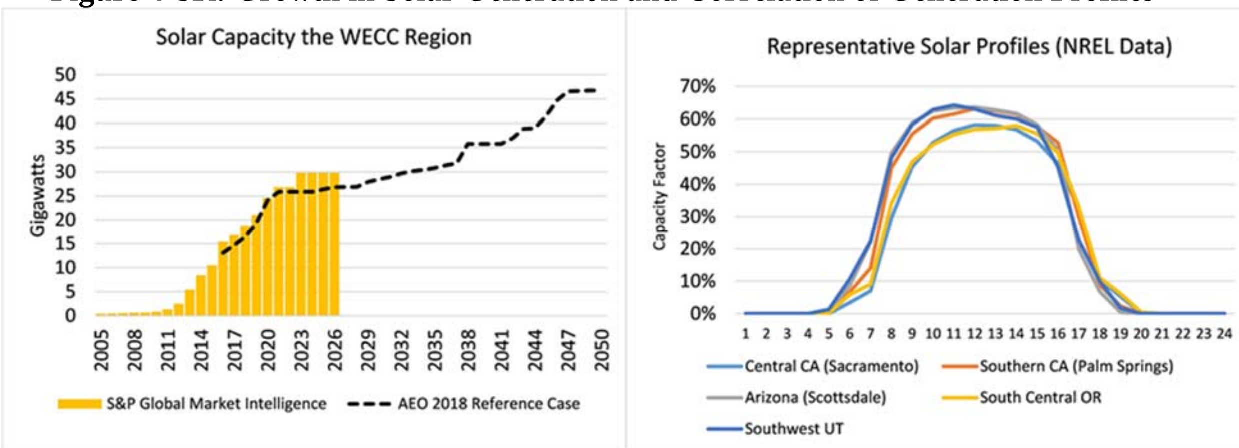
The price-policy scenario assumptions used to analyze solar-PPA bids in the 2017S RFP are identical to those used to analyze the Combined Projects in my second supplemental direct testimony, with the exception that the medium CO_2 price assumptions were correctly applied as a nominal cost instead of 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 solar 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, the 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 4-SR: Growth in Solar Generation and Correlation of Generation Profiles



Q. Did the independent evaluator for the 2017S RFP comment on the hourly price sensitivity?

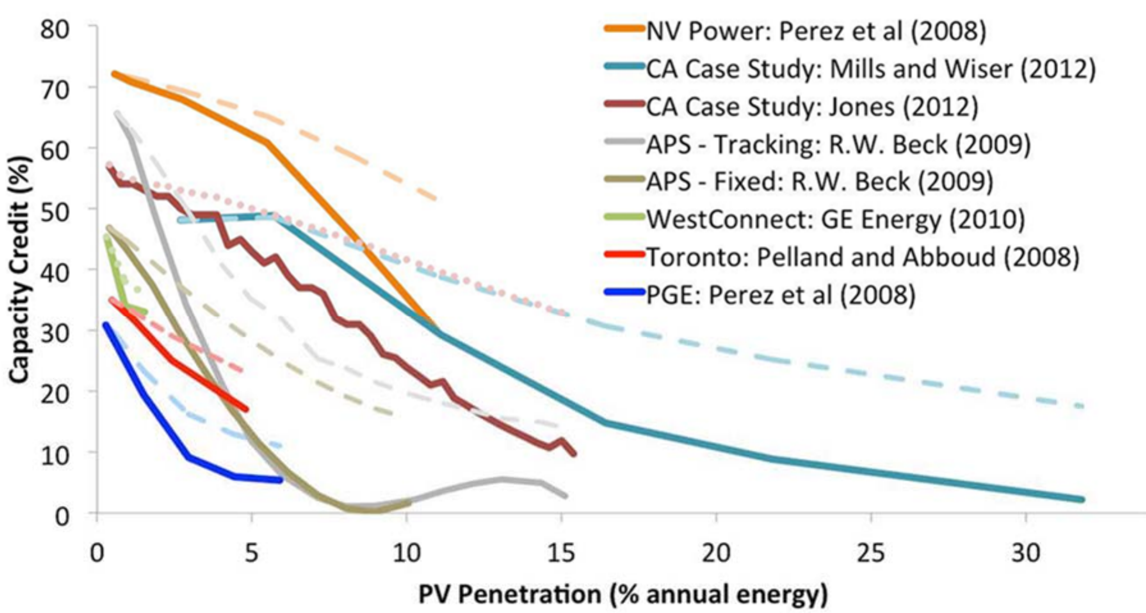
A. Yes. The independent evaluator concluded that the “alternative price profile was a reasonable way to examine potential downside risks to customers of committing to solar resources.” (Solar IE Report at 25.)

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 evaluate bids submitted into 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 located in Utah), and therefore the base economic analysis assumes that the 1,320 MW of solar-PPA capacity included 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 5-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, future IRPs, and future regulatory filings, 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 4-SR: Solar-Only Compared to Combined Projects
Hourly-Price Sensitivity System Modeling Results
(Medium Gas, Medium CO2)

	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. 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.

Table 5-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 6-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?

A. 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 7-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.

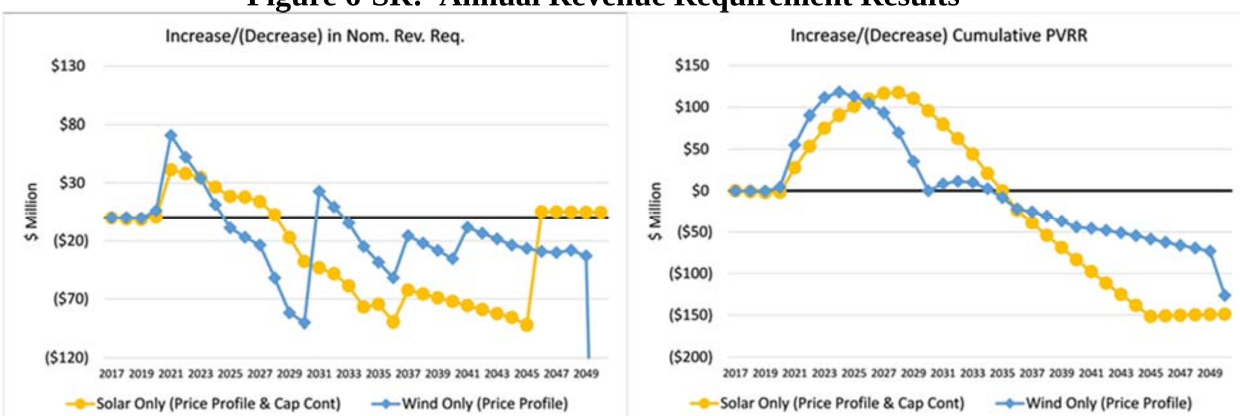
Q. What conclusions can you draw from these sensitivities?

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 PacifiCorp 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 6-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 6-SR: Annual Revenue Requirement Results



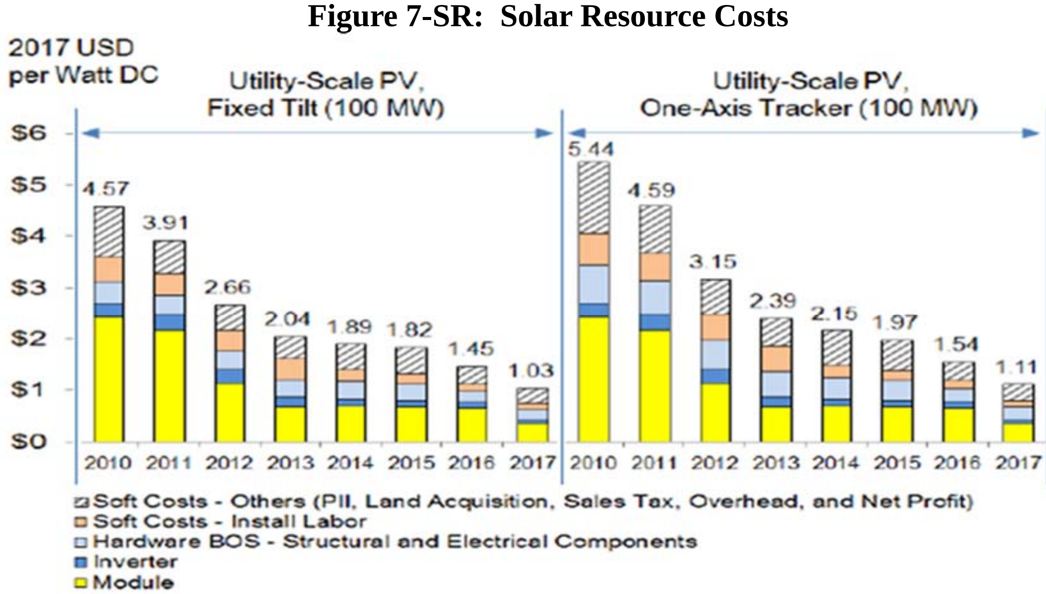
As Figure 6-SR illustrates, the PVRR(d) benefits of the Combined Projects, reflecting an hourly price profile derived from the CAISO day-ahead data, when calculated from nominal revenue requirement results is $127 million. The PVRR(d) benefits of the solar PPAs, reflecting an hourly price profile derived 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 7-SR, solar resource costs have been steadily declining and the trend is expected to continue.

Figure 7-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.[2] 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

[2] "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).

premium associated with tariff and tax-reform uncertainties.

Q. Mr. Hayet claims that the company did not discuss the nominal revenue requirement results through 2050 for the solar sensitivity presented in the second supplemental direct testimony. (Hayet Second Rebuttal, lines 557–585.) How do you respond?

A. As I described in my supplemental and second supplemental direct testimonies, 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. Hayet does not dispute that conclusion.

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. Mullins and Mr. Hayet claim that the nominal revenue-requirement results show that solar PPAs are a superior resource option when compared to the Combined Projects. (Hayet Second Rebuttal, lines 557–585; Mullins Supplemental Rebuttal, lines 402–411.) How do you respond?

A. First, Mr. Hayet and Mr. Mullins do 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 direct testimony are overstated, as demonstrated by the additional sensitivities discussed above, and that these risks could increase over time.

Q. If the Bridger/Anticline transmission line is included in the base case as discussed above, does that demonstrate that the Combined Projects are more favorable than solar PPAs in the nominal revenue-requirement results?

A. Yes. Including the net present-value costs of the transmission line in the base case adds $293 million in net benefits to the Combined Projects, for a total of $467 million in net benefits in the medium case.

Q. These witnesses also claim that the solar option is also less risky than the Combined Projects because the solar resources are PPAs. (Mullins Supplemental Rebuttal, lines 421-422; Hayet Second Rebuttal, lines 581-585.) Is this true?

A. No. These parties' 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 relatively 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. Dr. Zenger and Mr. Hayet claim that the solar PPAs are less risky because they do not require the Aeolus-to-Bridger/Anticline transmission line. (Zenger Supplemental Rebuttal and Surrebuttal, lines 207–210; Hayet Second Rebuttal, lines 581–583.) But, as described by Mr. Vail, that transmission line is needed today and 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 cost offset provided by the PTC-eligible Wind Projects. And as I discussed earlier, the company's economic analysis of the Combined Projects is conservative because it does not consider the cost of the Aeolus-to-Bridger/Anticline transmission line in the base case. As shown above, accounting for this cost in the base case would improve the net benefits from the Combined Projects by hundreds of millions of dollars in all price-policy scenarios.

Q. Dr. Zenger claims that "Utah solar resources should have been considered in this docket along with the Combined Projects." (Zenger Supplemental Rebuttal and Surrebuttal, lines 213–215.) Is this position consistent with DPU's prior position on the 2017R RFP?

A. No. In the docket where the Commission approved the 2017R RFP, DPU testified that the "RFP should be restricted to wind-only resources" because the "point of issuing the RFP is to potentially reap the benefits of the PTCs." *In the Matter of the Application of Rocky Mountain Power for Approval of Solicitation Process of Wind Resources*, Docket No. 17-0035-23, DPU Exhibit 1.0 REB, lines 151–152 (Sept. 13, 2017).

CONCLUSION

Q. Please summarize the conclusions of your surrebuttal testimony.

A. As confirmed by two different independent evaluators, the 2017R RFP was fair, transparent, and unbiased. The independent evaluators 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 independent evaluator found that the final shortlist of 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 through bi-lateral opportunities and 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 partially offset projected capacity needs and 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 surrebuttal testimony?

A. Yes.