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
Second Supplemental Direct Testimony of Rick T. Link

February 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 TESTIMONY

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

A. I summarize the updated results of the 2017R Request for Proposals ("RFP"). I also provide updates to the economic analysis that demonstrate increasing customer benefits from the new wind resources ("Wind Projects") and construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects"). I also provide information required by Public Service Commission of Utah ("Commission") Rule R746-430-2(1)(a), (b), (c), and (d) and Rule 746-440-1(1)(e) and (f).

Q. Please summarize your second supplemental direct testimony.

A. The updated 2017R RFP final shortlist replaces the company's McFadden Ridge II benchmark bid with the Ekola Flats benchmark bid. All of the other winning bids included in the original final shortlist remain in the updated final shortlist. The total capacity of the winning bids in the updated final shortlist is 1,311 MW, which includes three of the benchmark facilities (TB Flats I and II, now combined as a single project, and Ekola Flats), and two new facilities (Cedar Springs and Uinta). Uinta is a build-transfer agreement ("BTA") totaling 161 MW, Cedar Springs is one-half BTA and one-half power-purchase agreement ("PPA"), for a total of 400 MW, and TB Flats I and II and Ekola Flats are company-built facilities, totaling 500 MW and 250 MW, respectively.

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

- The Combined Projects continue to provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $196 million in the medium case through 2050 (as compared to $177 million in the supplemental direct filing), and range from $333 million to $405 million in the medium case through 2036.
- The analysis reflects consideration of an interconnection-restudy process, that: 1) eliminated certain bids, including the company's McFadden Ridge II benchmark bid, from consideration in the 2017R RFP; and 2) supported an increase to the assumed level of interconnection capacity in the constrained area of PacifiCorp's system in eastern Wyoming.
- Sensitivity analysis continues to show substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced or reduced when considering the potential procurement of solar PPA bids, updated with best-and-final pricing, submitted into the on-going RFP for solar resources, the 2017S RFP.

UPDATED 2017R RFP FINAL SHORTLIST

Q. Did the company update the list of winning bids from the 2017R RFP?

A. Yes. The company's 109 MW McFadden Ridge II benchmark resource was removed from the final shortlist and replaced with the company's 250 MW Ekola Flats benchmark resource. All of the other winning bids included in the original final shortlist remain in the updated final shortlist. The total capacity of the winning bids in the updated final shortlist is 1,311 MW. The winning bids included in the updated final shortlist are listed in Table 1-SS.

Table 1-SS. Updated 2017R RFP Final Shortlist

Project Name (Bidder)	Location	Capacity (MW)
TB Flats I & II (PacifiCorp)	Carbon & Albany Counties, WY	500
Cedar Springs (NextEra Energy Acquisitions)	Converse County, WY	400
Ekola Flats (PacifiCorp)	Carbon County, WY	250
Uinta (Invenergy Wind Development)	Uinta County, WY	161

The TB Flats I & II and Ekola Flats projects are company-benchmark resources that will be developed under engineer, procure, and construction ("EPC") agreements. The Uinta project is being developed by Invenergy Wind Development under a BTA. The Cedar Springs project is being developed by NextEra Energy Acquisitions as a 50-percent BTA and a 50-percent PPA. In total, the updated final shortlist includes 361 MW that will be developed under BTAs, 750 MW of benchmark capacity that will be developed under EPC agreements, and 200 MW that will deliver energy and capacity under a PPA.

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

A. The total in-service capital cost for the winning bids is $1.46 billion. Considering that the winning bids represent an increase in total owned-wind capacity (from just over 860 MW in the company's initial filing to approximately 1,111 MW), the per-unit capital cost for the updated final shortlist is down approximately 18 percent from $1,590/kW to $1,310/kW.

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

In aggregate, the winning bids are expected to operate at a capacity-weighted average annual capacity factor of 39.4 percent.

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

Q. Why was the 2017R RFP final shortlist updated?

A. The 2017R RFP final shortlist was updated to account for the results of an interconnection-restudy process. As described in Mr. Rick A. Vail's second supplemental direct testimony, the company completed an interconnection-restudy process to ensure that interconnection studies reflected the most current long-term transmission plan to construct the Aeolus-to-Bridger/Anticline D.2 segment of the Energy Gateway project by the end of 2020. PacifiCorp transmission restudied, in serial interconnection-queue order, interconnection requests that do not already have an interconnection agreement to determine whether the staging of the Energy Gateway West project would affect the cost or timing of projects whose previous interconnection studies depended on Gateway West in its entirety. Affected projects located in the constrained area of PacifiCorp's transmission system in eastern Wyoming were restudied through the point in the interconnection queue where additional segments of the Energy Gateway project beyond just the Aeolus-to-Bridger/Anticline D.2 segment would be required to interconnect.

PacifiCorp transmission posted the restudied system-impact studies ("SISs") on PacifiCorp's open access same-time information system ("OASIS") on January 29, 2018, as well as certain updated restudied SISs on February 9, 2018.

Q. How did the interconnection-restudy process affect 2017R RFP winning bid selections?

A. As described by Mr. Vail, the interconnection-restudy process confirmed that 2017R

RFP bids located in eastern Wyoming with an interconnection-queue position greater than Q0712 trigger the need for Energy Gateway South, which is not planned to be placed in service by the end of 2020. Consequently, any bid proposing a project in the constrained area of PacifiCorp's transmission system with an interconnection-queue position greater than Q0712 cannot receive interconnection service and achieve commercial operation by the end of 2020 as required in the 2017R RFP. This includes the company's McFadden Ridge II benchmark bid that was originally selected to the final shortlist. All other bids originally selected to the final shortlist can secure interconnection service either because they hold an interconnection-queue position that does not require Energy Gateway South (Ekola Flats, TB Flats I and II, and Cedar Springs) or because the project is not located in the constrained area of the company's eastern Wyoming transmission system (Uinta).

Q. Were there other findings from the interconnection-restudy process that affected selection of winning bids to the updated 2017R RFP final shortlist?

A. Yes. As noted by Mr. Vail, the interconnection-restudy process shows that the Aeolus-to-Bridger/Anticline transmission line will enable interconnection of up to 1,510 MW of new wind capacity within the constrained area of PacifiCorp's transmission system in eastern Wyoming. This is up from the 1,270 MW assumed in the bid-selection process summarized in my supplemental direct testimony.

As stated in my supplemental direct testimony, there is a 240 MW qualifying facility ("QF") project with an executed interconnection agreement that does not require construction of Energy Gateway West and South to accommodate the QF's interconnection. To honor this agreement, the company must reserve sufficient interconnection capacity for this interconnection customer. After setting aside interconnection capacity for this interconnection customer, the interconnection-restudy process shows that the Aeolus-to-Bridger/Anticline transmission line can enable interconnection of up to 1,270 MW of new wind located in the constrained area of PacifiCorp's transmission system in eastern Wyoming. This is up from the 1,030 MW assumed in the bid-selection process summarized in my supplemental direct testimony.

Q. Why did the company not consider the interconnection-queue position of bids when it originally identified bids selected to the final shortlist?

A. The company has been aware that it would need to factor interconnection requirements into its evaluation of the 2017R RFP bids since the beginning of the RFP process. Indeed, the company originally included a completed SIS as one of the minimum bid-eligibility requirements. In response, however, to recommendations from the Utah independent evaluator ("IE"), as supported by other parties in the 2017R RFP approval process in Docket 17-035-23, the company agreed to remove the requirement that a bidder have a completed SIS to be eligible to submit a proposal.

Q. Did elimination of the SIS requirement benefit the 2017R RFP process?

A. Yes. While the removal of the SIS requirement meant that the company could not fully evaluate the relative interconnection requirements of the bids early in the process, it agreed to relax the requirement that bidders have a completed SIS to broaden market participation in the 2017R RFP because bidders could participate without regard to their interconnection queue position. This enhances competition and provides an incentive for bidders to offer low-cost proposals. In addition, the interconnection queue can change over time as generator-interconnection customers change project details, request commercial operation date extensions or suspensions, or even withdraw from the queue altogether.

Had the requirement that bidders have a SIS been retained, the pool of eligible bidders would have been limited based on the then-current snapshot of the interconnection queue, which would have reduced competitive forces that drive least-cost bidding.

Q. How did the company establish its updated final shortlist that accounts for the findings from the interconnection-restudy process?

A. The company produced updated portfolio-development studies using the System Optimizer ("SO") model to create a bid portfolio containing the least-cost combination of viable bids. In choosing the least-cost combination of bids, the SO model was configured to select from all viable bid alternatives, excluding bids located in the constrained area of PacifiCorp's transmission system in eastern Wyoming, that have an interconnection-queue position greater than Q0712. Consistent with the increased interconnection capability identified during the interconnection-restudy process, the SO model was also configured to select up to 1,270 MW of bids located in this area of PacifiCorp's transmission system. The updated portfolio-development studies were developed under two price-policy scenarios-low natural gas, zero CO_2 and medium natural gas, medium CO_2.

Q. Did the company update its price-policy scenario assumptions?

A. No. The price-policy scenario assumptions summarized in my supplemental direct testimony remain valid and were not updated for this analysis.

Q. Why did the company update its portfolio-development studies using only the low natural gas, zero CO_2 and medium natural gas, medium CO_2 price-policy assumptions?

A. As described in my supplemental direct testimony, the company originally produced least-cost bid portfolios for all nine price-policy scenarios. That analysis identified a bid portfolio that included the original final shortlist of projects plus an additional bid. The additional bid was included in the bid portfolio only in the medium natural gas, high CO_2 price-policy scenario and in the three price-policy scenarios that assume high natural gas price assumptions. The bid portfolio with the incremental bid did not generate favorable net benefits for customers relative to the portfolio containing the original final shortlist of projects when applying low natural gas price-policy assumptions or when applying price-policy assumptions paring medium natural gas prices with zero or medium CO_2 prices. Based on these results, the company evaluated bid selections assuming base case (medium natural gas, medium CO_2 price) and worst case (low natural gas, zero CO_2) price-policy assumptions.

Q. Did the company update any bid-cost assumptions when developing its updated portfolio-development studies?

A. Yes. The company updated bid-cost assumptions to align interconnection network upgrade costs with those identified in the SISs posted on PacifiCorp's OASIS. The company also updated sales-tax estimates for all bids submitted by [redacted]-replacing the company's sales-tax estimates assumed when establishing the original final shortlist with sales-tax costs supplied by the bidder.

Q. What bids were selected by the SO model in the updated portfolio-development studies?

A. The SO model selected the same four bids, included in the company's updated final shortlist as summarized in Table 1-SS, in the low natural gas, zero CO_2 and the medium natural gas, medium CO_2 price-policy scenarios.

Q. Did the company update its economic analysis to account for the updated final shortlist?

A. Yes. The economic analysis among all nine price-policy scenarios was refreshed to reflect those bids selected in the updated 2017R RFP final shortlist. This analysis was updated using the SO model and the Planning and Risk model ("PaR"). I describe the company's updated economic analysis later in my testimony.

Q. Did the company inform the Utah and Oregon IEs of changes to the 2017R RFP final shortlist resulting from the interconnection-restudy process described above?

A. Yes. On January 19, 2018, the company discussed the potential impacts of the interconnection-restudy process with the Utah and Oregon IEs. Specifically, the company explained that, although no definitive determinations could be made until restudy process was completed, certain bids with a relatively high interconnection-queue position located in eastern Wyoming, including the company's McFadden Ridge II benchmark, may not be viable. On February 12, 2018, after the interconnection-restudy process and bid-selection analysis was completed, the company submitted its updated final shortlist recommendation to the Utah and Oregon IEs.

Q. Did the Utah and Oregon IEs request any additional sensitivity studies as the company was finalizing its updated final shortlist recommendation?

A. Yes. The Utah and Oregon IEs requested a sensitivity to assess how projected net benefits from the updated final shortlist would be affected if [redacted] The Utah and Oregon IEs requested that this sensitivity be developed using the SO model with medium natural gas, medium CO_2 price-policy scenario assumptions.

Q. What were the findings from this IE sensitivity?

A. The present-value revenue requirement differential ("PVRR(d)") based on SO model results through 2036 under the IE sensitivity showed a $25 million reduction in net customer benefits if [redacted]. The IE sensitivity also showed customer costs would increase over both the near term and long term if [redacted].

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

A. No.

Q. Does the Utah IE report on the 2017R RFP final shortlist, dated February 15, 2018, support the final shortlist?

A. Yes. The IE concluded that the Company conducted the 2017R RFP in a consistent and fair manner and agreed that the Company's final shortlist was reasonable.

UPDATED ECONOMIC ANALYSIS

Q. Did the Company refresh any other assumptions not already identified above in the updated final shortlist economic analysis?

A. No.

Q. Did the company continue to apply production tax credit ("PTC") benefits applicable to BTAs and benchmark-EPC bids on a nominal basis in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. As described in my supplemental direct testimony, this approach better reflects how the federal PTC benefits for these bids will flow through to customers and aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050. It also ensures the 2017R RFP bid selections from the SO model more accurately reflect the difference in how BTA and benchmark-EPC bids are expected to impact customer rates.

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

A. Yes. As discussed in my supplemental direct testimony, when setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because revenue requirement from capital projects is spread over the life of the asset in rates, these costs continue to be treated as a levelized cost in the SO model and PaR simulations.

Q. Did the company update its revenue-requirement modeling among different price-policy scenarios to reflect the updated final shortlist and modeling updates described above?

A. Yes. Using the same annual revenue-requirement modeling methodology described in my direct and supplemental direct testimony, the company updated its forecast of the change in nominal annual revenue requirement due to the Combined Projects. As was done in the economic analysis summarized in my direct and supplemental direct testimony, revenue requirement from capital associated with the Combined Projects is treated as a nominal cost when the results are extrapolated out through 2050.

UPDATED SYSTEM MODELING PRICE-POLICY RESULTS

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

A. Table 2-SS summarizes the updated PVRR(d) results for each price-policy scenario alongside the same results summarized in my supplemental direct testimony. The PVRR(d) between cases with and without the Combined Projects, reflecting the updated final shortlist from the 2017R RFP, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the updated PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-2SS).

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

Price-Policy Scenario	Second Supplemental Direct (Updated Final Shortlist)			Supplemental Direct (Original Final Shortlist)		
	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($185)	($126)	($132)	($145)	($104)	($109)
Low Gas, Medium CO_2	($208)	($155)	($164)	($186)	($124)	($131)
Low Gas, High CO_2	($370)	($313)	($331)	($297)	($258)	($272)
Medium Gas, Zero CO_2	($377)	($295)	($310)	($306)	($246)	($258)
Medium Gas, Medium CO_2	($405)	($333)	($362)	($343)	($311)	($327)
Medium Gas, High CO_2	($489)	$(424)	($445)	($430)	($388)	($406)
High Gas, Zero CO_2	($699)	($545)	($572)	($619)	($509)	($535)
High Gas, Medium CO_2	($716)	($579)	($609)	($636)	($539)	($567)
High Gas, High CO_2	($781)	($671)	($705)	($696)	($605)	($636)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $333 million (up from $311 million), when derived from PaR stochastic-mean results, and $405 million (up from $343 million), when derived from SO model results. Net benefits increase relative to those shown in my supplemental direct testimony. This is driven by the increased interconnection capacity associated with the Aeolus-to-Bridger/Anticline transmission line, which enables selection of the Ekola Flats benchmark resource. Without this update, there was not sufficient interconnection capacity to accommodate the Ekola Flats benchmark with the TB Flats I & II and Cedar Springs bids.

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

A. Yes. Consistent with my direct and supplemental direct testimony, the PVRR(d) results presented in Table 2-SS do not reflect the potential value of RECs generated by the incremental energy output from the updated final shortlist projects. Accounting for the performance estimates from the updated final shortlist projects, customer benefits for all price-policy scenarios would improve by approximately $34 million (up from $31 million in my supplemental direct analysis) for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2036. Quantifying the potential upside associated with incremental REC revenues is simply intended to communicate that the net benefits from the winning bids could improve if the incremental RECs can be monetized in the market.

Q. Did you update the potential upside to these PVRR(d) results associated with reduced operations & maintenance ("O&M") costs?

A. Yes. Consistent with my supplemental direct testimony, projects with large wind turbines are expected to require less O&M costs because there are fewer turbines on a given site. The default O&M assumptions applied to BTA and benchmark-EPC bids in the updated economic analysis are based on the company's experience in operating and maintaining the existing fleet of owned-wind facilities, and do not reflect expected cost savings associated with operating and maintaining wind facilities proposing to use larger wind turbines. Three of the winning bids--Invenergy Wind Development's Uinta project, the company's TB Flats I & II project, and the company's Ekola Flats project--will use larger equipment for a portion of the wind turbines at each facility. If the O&M

cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18-percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $19 million (up from $13 million in my supplemental direct testimony).

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

A. Yes. The CO_2 price assumptions used in the updated economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

UPDATED REVENUE-REQUIREMENT MODELING PRICE-POLICY RESULTS

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

A. Table 3-SS summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050 alongside the same results summarized in my supplemental direct testimony. The annual data over the period 2017 through 2050 that was used to calculate the updated PVRR(d) results shown in the table are provided as Exhibit RMP__(RTL-3SS).

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

Price-Policy Scenario	Second Supplemental Direct (Updated Final Shortlist)	Supplemental Direct (Original Final Shortlist)
Low Gas, Zero CO_2	$155	$169
Low Gas, Medium CO_2	$98	$133
Low Gas, High CO_2	($176)	($105)
Medium Gas, Zero CO_2	($121)	($60)
Medium Gas, Medium CO_2	($196)	($177)
Medium Gas, High CO_2	($333)	($301)
High Gas, Zero CO_2	($477)	($437)
High Gas, Medium CO_2	($528)	($479)
High Gas, High CO_2	($664)	($585)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the updated 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer net benefits range from $121 million in the medium natural-gas, zero CO_2 price-policy scenario (up from $60 million) to $664 million in the high natural gas, high CO_2 price-policy scenario (up from $585 million). Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) benefits of the Combined Projects are $196 million (up from $177 million). The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results continue to show that upside benefits far outweigh downside risks.

As is the case with the system-modeling results, net benefits increase relative to those shown in my supplemental direct testimony. As stated earlier, this is driven by the increased interconnection capacity associated with the Aeolus-to-Bridger/Anticline transmission line, which enables selection of the Ekola Flats benchmark resource. Without this update, there was not sufficient interconnection capacity to accommodate the Ekola Flats benchmark with the TB Flats I & II and Cedar Springs bids.

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

A. Yes. Consistent with my direct and supplemental direct testimony, the PVRR(d) results presented in Table 3-SS do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the performance estimates from the updated final shortlist projects, customer benefits for all price-policy scenarios would improve by approximately $43 million (up from $39 million in my supplemental direct analysis) for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2050.

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

A. Yes. As discussed above, the company anticipates O&M costs for those projects that will install larger-turbine equipment to be lower than what has been reflected in the updated economic analysis. Accounting for these cost savings, customer benefits for all price-policy scenarios would improve by approximately $31 million (up from $22 million in my supplemental direct testimony) when calculated from projected operating costs through 2050.

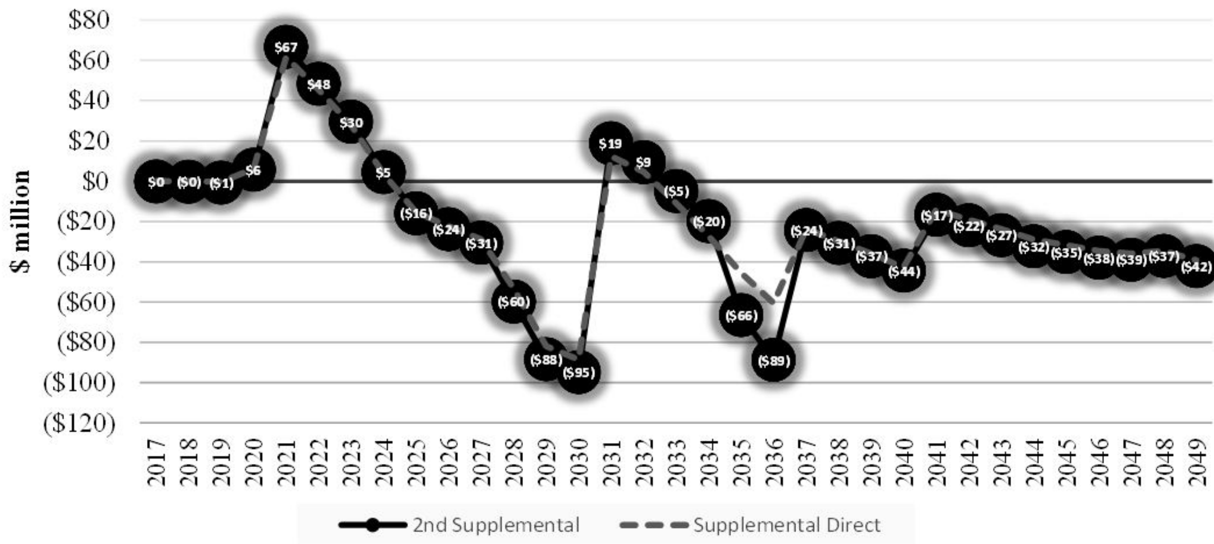
Q. Is there additional potential upside to these PVRR(d) results shown in Table 3-SS?

A. Yes. As noted earlier, the updated CO_2 price assumptions used in the updated economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

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

A. Figure 1-SS shows the updated change in nominal revenue requirement due to the Combined Projects for the medium natural gas, medium CO_2 price-policy scenario on a total-system basis. These results are shown alongside the same results from the economic analysis summarized in my supplemental direct testimony. The change in nominal revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 1-SS Updated Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the economic analysis summarized in my supplemental direct testimony. Despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits and continue to contribute to customer benefits over the long term. The Combined Projects produce net benefits in 23 years out of the 30 years that the proposed owned-wind resources selected to the 2017R RFP final shortlist are assumed to operate.

As noted in my supplemental direct testimony, the year-on-year reduction in net benefits from 2036 to 2037 is driven by the company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028-through-2036 time frame. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2035-to-2036 time frame. This extrapolation methodology is conservative because it results in project benefits not matching the levels observed in the model results for 2036 until 2047.

SOLAR SENSITIVITY

Q. Did the company update its solar sensitivity analysis?

A. Yes. The solar sensitivity analysis was updated to reflect the updated final shortlist from the 2017R RFP and to reflect best-and-final pricing supplied by bidders participating in the 2017S RFP on February 1, 2018.

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

A. Consistent with the methodology summarized in my supplemental direct testimony, the company's solar sensitivity analysis used the SO model and PaR simulations to determine the PVRR(d) based on two model runs--one with solar PPA bids and the Combined Projects and one with solar PPA bids but without the Combined Projects.

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

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

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

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($343)	($405)	$61
PaR Stochastic Mean	($206)	($333)	$127
PaR Risk Adjusted	($216)	($362)	$146
Low Gas, Zero CO2			
SO Model	($196)	($185)	($11)
PaR Stochastic Mean	($123)	($126)	$3
PaR Risk Adjusted	($130)	($132)	$3

In this sensitivity, the SO model selects 1,122 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. All of the selected solar PPA bids are for projects located in Utah.

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $146 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with the Combined Projects delivers slightly greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects when modeled in PaR, and slightly lower customer benefits when analyzed with the SO model. The decrease in net benefits in the solar PPA portfolio is $3 million based on the risk-adjusted PaR results.

When analyzed without the Combined Projects, the solar PPA bids produce net customer benefits that are lower than the benefits expected from the Combined Projects in the medium natural gas, medium CO_2 price-policy scenario. While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces PVRR(d) results that are similar to the PVRR(d) results with only the Combined Projects in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. This sensitivity does not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table.

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

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

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

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($647)	($405)	($242)
PaR Stochastic Mean	($455)	($333)	($122)
PaR Risk Adjusted	($479)	($362)	($116)
Low Gas, Zero CO2			
SO Model	($312)	($185)	($127)
PaR Stochastic Mean	($197)	($126)	($71)
PaR Risk Adjusted	($206)	($132)	($74)

In this sensitivity, the SO model continues to choose the winning bids included in the updated 2017R RFP final shortlist as part of the least-cost bid portfolio. In addition to these wind resource selections, the SO model selects 1,042 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. Again, all of the selected solar PPA bids are for projects located in Utah.

When the solar PPAs are assumed to be pursued in addition to the Combined Projects, total net customer benefits increase. This result is consistent with the company's expectation expressed during the 2017R RFP approval process in Docket No. 17-035-23 that cost-effective solar opportunities would not displace the Combined Projects, but would only potentially add to incremental resource procurement opportunities that might provide net customer benefits. Importantly, this sensitivity produces net benefits that are greater than the net benefits from the Combined Projects without the solar PPAs. This confirms that near-term renewable procurement is not a matter of whether the company should pursue the Combined Projects *or* the solar PPAs, but whether the company should consider both opportunities. At this time, it is clear that the Combined Projects provide significant net benefits, and that these benefits are not eliminated if the company were to also pursue solar PPA bids through the 2017S RFP.

WIND-REPOWERING SENSITIVITY

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

A. Yes. The wind repowering sensitivity was updated to reflect the updated final shortlist and to reflect the most recent cost-and performance estimates for the wind repowering project as described in my supplemental direct testimony filed in Docket No. 17-035-39.

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

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

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

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO2			
SO Model	($608)	($405)	($204)
PaR Stochastic Mean	($517)	($333)	($184)
PaR Risk Adjusted	($543)	($362)	($181)
Low Gas, Zero CO2			
SO Model	($334)	($185)	($149)
PaR Stochastic Mean	($257)	($126)	($131)
PaR Risk Adjusted	($271)	($132)	($138)

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

TURBINE-EQUIPMENT SENSITIVITY

Q. Did the company perform any other additional sensitivity analysis to support selection of bids to the updated 2017R RFP final shortlist?

A. Yes. The company produced an SO model sensitivity to analyze the PVRR(d) impact of [redacted].

Q. Why did the company develop this sensitivity?

A. Technical discussions and preliminary modeling of [redacted] in the interconnection-restudy process raised concerns that a synchronous condenser or other electrical compensation equipment might be required at the Aeolus substation if the [redacted] to address system performance in a low stiffness-factor environment. Considering that [redacted], the company produced this sensitivity to estimate the incremental amount of network upgrade costs that would [redacted].

Q. What were the results of this turbine-equipment sensitivity?

A. Table 7-SS summarizes PVRR(d) results for the turbine-equipment sensitivity. This sensitivity was developed using the SO model through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated with the updated final shortlist of bids.

Table 7-SS Turbine-Equipment
Sensitivity (Benefit)/Cost ($ million)

	Sensitivity	Benchmark	Change in
Medium Gas, Medium CO_2	($381)	($405)	$24
Low Gas, Zero CO_2	($143)	($185)	$42

Considering that the SO model uses levelized capital costs, the reduction in PVRR(d) net benefits in this sensitivity would require at least [redacted] in incremental in-service transmission upgrade costs attributable to [redacted].

The company does not anticipate that incremental in-service transmission costs would exceed [redacted] should a synchronous condenser or other electrical compensation equipment be required. Moreover, [redacted] Based on these findings [redacted], PacifiCorp did not [redacted].

COMPLIANCE WITH UTAH ADMIN. CODE RULE R746-430-2

Q. Does your testimony and exhibits include the information required for an application for approval of the significant energy resource decision to acquire the Wind Projects?

A. Yes. It is my understanding Utah Admin. Code Rule R746-430-2(1)(a)-(h) sets forth the filing requirements for a request for approval of a significant energy resource decision. My testimony and exhibits address the requirements in Utah Admin. Code Rule R746-430-2(1)(a), (b), (c) and (d).

Q. Has the company provided "[i]nformation to demonstrate that the utility has complied with the requirements of the Energy Resource Procurement Act and Commission rules," as required by Utah Admin. Code Rule R746-430-2(1)(a)?

A. Yes. As relevant to my testimony, the 2017R RFP was approved by the Commission and executed consistent with the requirements of Part 2 of the Energy Resource Procurement Act ("Act") and consistent with the Commission's rules implementing that section of the Act. Attached to my testimony as Exhibit RMP___(RTL-4SS) is my affidavit attesting that the 2017R RFP complied with the requirements of the Act.

Q. Has the Company provided "[i]nformation to demonstrate whether the approval of the selected Significant Energy Resource is in the public interest," as required by Utah Admin. Code Rule R746-430-2(1)(b)?

A. Yes. My direct, supplemental direct and rebuttal, and second supplemental direct testimony demonstrate that the procurement of the Wind Projects is expected to provide substantial customer benefits and is the least-cost, least-risk resource choice to serve Utah customers. In addition, Mr. Teply's and Mr. Vail's testimony demonstrates how the company will reasonably manage the risks associated with the procurement of the Wind Projects and the steps that are being taken to ensure that the Wind Projects are online by the end of 2020 and therefore fully eligible to qualify for federal PTCs.

Q. Please describe the filing requirements set forth in Utah Admin. Code Rule R746-430-2(1)(c), which addresses the solicitation process.

A. Utah Admin. Code Rule R746-430-2(1)(c) requires the company to provide the following:

> Information regarding the solicitation process, if the Significant Energy Resource was solicited through a solicitation process, including, but not limited to:
> (i) Summaries of all bids received;
> (ii) Summaries of the Affected Utility's rankings and evaluations of bids;
> (iii) Copies of all reports relating to the solicitation process made by an independent evaluator who may have been involved with the solicitation process;
> (iv) A copy of the complete Commission approved Solicitation with appendices, attachments and drafts, if applicable; and
> (v) A signed acknowledgment from a utility officer involved in the solicitation that to the best of his or her knowledge, the utility fully observed and complied with the requirements of the Commission's rules or statutes applicable to the solicitation process
> .

Q. Has the company provided summaries of all bids received, as required by Utah Admin. Code Rule R746-430-2(1)(c)(i)?

A. Yes. Confidential Exhibit RMP___(RTL-5SS) summarizes the bids that were received and reviewed as part of the 2017R RFP. The Utah IE's monthly reports, which are attached as Highly Confidential Exhibit RMP___(RTL-6SS), also include a summary of all of the bids that were included on the 2017R RFP initial shortlist. The non-conforming bids that were received and rejected are described in Highly Confidential Exhibit RMP___(RTL-7SS).

Q. Has the company provided summaries of its rankings and evaluations of bids, as required by Utah Admin. Code Rule R746-430-2(1)(c)(ii)?

A. Yes. Highly Confidential Exhibit RMP___(RTL-8SS) provides a summary of the company's rankings and evaluation of bids. In addition, my supplemental direct and rebuttal testimony, filed January 16, 2018, and my testimony above describes how the company evaluated bids using the SO model and PaR to identify the final-shortlist projects.

Q. Has the company provided the reports prepared by the Utah IE, as required by Utah Admin. Code Rule R746-430-2(1)(c)(iii)?

A. Yes, the Company has provided all Utah IE reports received to date. Specifically, Highly Confidential Exhibit RMP___(RTL-6SS) provides copies of all the monthly status reports prepared by the IE. The exhibit also includes the Utah IE's final report on the assessment of the Company's benchmark resources (*i.e.*, TB Flats I and II, Ekola Flats, and McFadden Ridge II), which was prepared by the IE on November 2, 2017, and the Utah IE's report on the 2017R RFP final shortlist, which was prepared by the IE on February 15, 2018.

Q. What were the Utah IE's conclusions related to the benchmark resources?

A. The IE found that the company "developed detailed cost information about the benchmark resources and provided their proposals along with the background information and spreadsheets detailing the cost by line item to the IEs for review and assessment of the benchmark resources."

The IE concluded that the "benchmark proposals contain all the information required of other bidders and will be evaluated consistent with the methodology used to evaluate all bids submitted." According to the IE, the "level and detail of information provided by [the Company] is very thorough and <u>exceeds industry standards</u> for benchmark resources at this stage in the process." (emphasis added).

Regarding the cost estimates for the benchmark resources, the IE concluded that, "[o]verall, we feel that the capital costs are reasonable for the benchmark resources but if there is any deviation from the average we feel it would be on the low side of the cost spectrum." Similarly, the IE concluded that the O&M costs are reasonable.

Overall, the IE concluded that the company's treatment of benchmark resources in the 2017R RFP conformed to the requirements of Utah Admin. Rule R746-420 and that the "review, assessment and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward perception of bias."

Q. What were the Utah IE's conclusions related to the 2017R RFP final shortlist?

A. As noted above, the IE agreed with the Company's final shortlist and specifically concluded the following:

- The response to the 2017R RFP was robust—the capacity bid into the RFP was more than five times the capacity requested, and bidders offered a variety of commercial structures;
- The Company's modeling demonstrates that pursuit of the Wind Projects should result in significant customer benefits, particularly in the near-term as PTC benefits flow through rates;
- The Company used a consistent evaluation process and treated all proposals equally;
- The final revised evaluation and shortlist is reasonable;
- The Company made a compelling case that it reasonably accounted for the interconnection queue position of project bids and eliminated projects with bid positions higher than Q0712.[1]

[1] While the details of the IE's report, particularly the summaries of bid information, is designated highly confidential, the IE's conclusions are non-confidential.

Q. Does Highly Confidential Exhibit RMP___(RTL-6SS) include the IE's final report?

A. No. The company has not received a copy of the IE's final report. But once the report is completed, the company will ensure that it is promptly filed with the commission, either by the Utah IE, or by the company. My understanding is that this approach was used in Docket No. 10-035-126 when the company requested approval of the significant energy resource decision to acquire the Lakeside 2 facility. In that case, the company filed its application on December 21, 2010, and the IE filed its final report on January 25, 2011. Despite this delay, the commission issued its final order on April 20, 2011-120 days after the company filed its application.

Q. Has the company included any reports filed by the IE appointed by the Public Utility Commission of Oregon (Oregon Commission)?

A. Yes. The Oregon Commission appointed Bates White, LLC as its IE. At this time, the Oregon IE has provided an assessment of the final draft RFP and a letter confirming its agreement with changes made to the final 2017R RFP, which are provided as Exhibit RMP___(RTL-9SS). The Oregon IE will file its closing report with the Oregon Commission on February 16, 2017. The company will file the Oregon IE's closing report with the Utah Commission once it is available.

Q. Has the company provided a copy of the complete Commission-approved 2017R RFP, with appendices, attachments, and drafts, as required by Utah Admin. Code Rule R746-430-2(1)(c)(iv)?

A. Yes. Due to its voluminous nature, the company has included the main body of the RFP document as Exhibit RMP___(RTL-10SS). The appendices and exhibits to the 2017R

RFP main document are being provided electronically as Exhibit RMP___(RTL-11SS).

Q. Is the 2017R RFP publicly available?

A. Yes. The 2017R RFP, along with all appendices and exhibits, has been available on the Company's website (http://www.pacificorp.com/sup/rfps/2017-rfp.html) since it was issued. In addition, although it is not the subject of this case, the 2017S RFP and all appendices are also publicly available on the Company's website (http://www.pacificorp.com/sup/rfps/2017S-RFP.html).

Q. Has the company provided a signed acknowledgment from a utility officer involved in the solicitation that to the best of his or her knowledge, the utility fully observed and complied with the requirements of the Commission's rules or statutes applicable to the solicitation process, as required by Utah Admin. Code Rule R746-430-2(1)(c)(v)?

A. Yes. The signed acknowledgment is attached as Exhibit RMP___(RTL4SS). It is my understanding that the Commission's final order approving the 2017R RFP, issued in Docket No. 17-035-23, has been appealed. My understanding, however, is that the Commission's order approving the 2017R RFP was not stayed pending the appeal and therefore remains in effect.

Q. Has the company provided "all information, data, models and analyses used by the [Company] . . . to evaluate and rank bids and the selected resource," as required by Utah Admin. Code Rule R746-430-2(1)(d)?

A. Yes. My direct testimony, supplemental direct and rebuttal testimony, and second supplemental direct testimony, along with the exhibits accompanying each, describe in detail how the company analyzed bids using the SO model and PaR. Section 6 of the

2017R RFP, included in Exhibit RMP___(RTL10SS), also describes the company's bid-evaluation methodology. And the company's third-party capacity factor review study, which includes additional review of the Uinta project that was not included in Confidential Exhibit RMP___(RTL-2SD), is provided as Confidential Exhibit RMP___(RTL-12SS). In addition, the company has included the following information, data, models and analyses used to evaluate and rank bids and the selected resources:

- Highly Confidential Exhibit RMP___(RTL-13SS) includes electronic copies of all screening models used to establish price scores for the 2017R RFP initial shortlist.
- Confidential Exhibit RMP___(RTL-14SS) includes electronic files used to establish non-price scores for the 2017R RFP initial shortlist.
- Highly Confidential Exhibit RMP___(RTL-15SS) includes electronic copies of all screening models used to process best-and-final pricing reflecting changes in tax law.
- Highly Confidential Exhibit RMP___(RTL-16SS) includes electronic copies of all screening models used to add sales tax costs to certain bids as described in my supplemental direct testimony.
- Highly Confidential Exhibit RMP___(RTL-17SS) includes electronic copies of all screening models used to capture updated interconnection network upgrade costs and sales tax costs for certain bids as described earlier in my second supplemental direct testimony.

- Highly Confidential Exhibit RMP___(RTL-18SS) includes final shortlist recommendations delivered to the Utah and Oregon IEs.

COMPLIANCE WITH UTAH ADMIN. CODE RULE R746-440-1

Q. Does your testimony and exhibits contain the information that must be included with a voluntary request for approval of a resource decision to construct the Transmission Projects?

A. Yes. It is my understanding Utah Admin. Code Rule R746-440-1(1) sets forth the filing requirements for a voluntary request for approval of a resource decision. My testimony and exhibits address the requirements in Utah Admin. Code Rule R746-440-1(1)(e) and (f).

Q. Has the Company provided "[d]escriptions and comparisons of other resources or alternatives evaluated or considered by the [Company], in lieu of the proposed Resource decision," as required by Utah Admin. Code Rule R746-440-1(e)?

A. Yes. My direct, supplemental direct and rebuttal, and second supplemental direct testimony, provide the information required by Utah Admin. Code Rule R746-440-1(e). Specifically, my direct testimony describes how the 2017 IRP selected new wind resources and transmission as part of the least-cost, least-risk resource portfolio to serve customers (Link Direct, lines 96-364). My supplemental direct and rebuttal testimony and second supplemental direct testimony further describe how the Company used the SO model and PaR to evaluate potential resource alternatives to the Combined Projects and demonstrate that the Combined Projects remain least-cost, least-risk resources.

Q. Has the Company provided "[s]ufficient data, information, spreadsheets, and models to permit an analysis and verification of the conclusions reached and models used by the [Company]," as required by Utah Admin. Code Rule R746-440-1(f)?

A. Yes. The same information I describe above that satisfies the similar requirement in Utah Admin. Code Rule R746-430-2(1)(d), also satisfies the requirement found in Utah Admin. Code Rule R746-440-1(f).

Q. Does this conclude your second supplemental direct testimony?

A. Yes.