BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

SUPPLEMENTAL REBUTTAL TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

THE UTAH ASSOCIATION OF ENERGY USERS

AND

THE UTAH INDUSTRIAL ENERGY CONSUMERS

April 17, 2018

TABLE OF CONTENTS TO THE
SUPPLEMENTAL REBUTTAL TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. ARE YOU THE SAME BRADLEY G. MULLINS THAT FILED DIRECT TESTIMONY IN THIS MATTER?

A. Yes. I previously filed testimony on behalf of the Utah Association of Energy Users ("UAE") and the Utah Industrial Energy Consumers ("UIEC"). My address has changed to 1750 SW Harbor Way, Suite 450, Portland, Oregon 97062.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. I respond to the Supplemental Direct Testimony of Rocky Mountain Power ("PacifiCorp") witnesses Rick Link, Rick Vail and Chad Teply concerning PacifiCorp's proposal to construct 1,311 MW of new wind resources in eastern Wyoming ("Wind Projects") and its proposal to construct a 140 mile high voltage 500 kV transmission line between Aeolis and Jim Bridger, including associated network upgrades, ("Transmission Projects"). Collectively, I refer to the Wind Projects and Transmission Projects as the "Combined Projects."

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. In addition to reviewing PacifiCorp's testimony and workpapers, I conducted discovery and reviewed PacifiCorp's response to data requests. Relevant responses to data requests can be found in UAE-UIEC Exhibit 3.1. I also review highly confidential documents relating to the bids received in both the Renewable Request for Proposal ("Wind RFP") issued on September 27, 2017 and the Request for Proposal Solar Resources ("Solar RFP") issued on November 15, 2017.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY?

A. As discussed in my Direct Testimony, there is no imminent need for new resources. In discovery, PacifiCorp indicated in its most recent load forecast that loads are forecast to decline between 2017 and 2036 on both a peak- and energy-basis.[1] As a result, PacifiCorp is still in a surplus capacity position through 2026, irrespective of how front office transactions are considered in the load and resource balance.

And even if one were to conclude that a resource need existed, PacifiCorp's final resource procurement proposal is not the least-cost, nor least-risk, alternative for taking advantage of increasingly low-priced wind and solar resources. In addition to uncertainty surrounding the legal challenge to the Wind RFP, the Wind RFP selection process was flawed. Nevertheless, the Wind RFP and Solar RFP demonstrate that the cost of renewable resources has been declining rapidly. Both the Utah and the Oregon independent evaluators acknowledged that there were low cost, lower risk power purchase agreements ("PPAs") available through the Wind RFP, which were disqualified solely based on the generator interconnection queue position of the respective wind sites. Further, PacifiCorp's solar sensitivity studies also demonstrated that the final and best pricing in the ongoing Solar RFP produced potential resources that appear to present lower cost and lower risk resources than the Combined Projects.

Finally, I also continue to disagree with many of the assumptions in PacifiCorp's benefits study. I have also identified a number of new modeling problems and flaws surrounding market prices, transmission revenues, transmission capital assumptions, and energy imbalance market benefits. After adjusting for these factors, my analysis suggests

---

1 See UAE-UIEC Exhibit 3.2 (Conf.).

that the Combined Projects will not produce a net present value ratepayer benefit and, in fact, will result in a net cost of $103,956,638 under the medium gas, medium CO2 scenario on a Net Present Value Revenue Requirement ("NPVRR") basis.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission decline to approve PacifiCorp's request for approval to construct the Wind Projects and voluntary request for approval to construct the Transmission Projects. The Commission's decision approving the RFP is on appeal, and the RFP may not withstand appellate review. Further, the RFP that ultimately took place was not the competitive RFP process that was described when PacifiCorp first filed this case.

Where a range of potentially beneficial alternatives exist, the utility must produce and deliver at the lowest reasonable costs with the lowest risk, consistent with the public interest requirements of the Energy Resources Procurement Act. When a utility chooses a generating resource that is second best or, in this case, not even close to the next best alternative, such a resource decision should not receive Commission preapproval.

Further, I continue to recommend that the Commission reject PacifiCorp's proposal for single-issue ratemaking through the proposed renewable resource tracking mechanism for the reasons described in my Direct Testimony

II. BACKGROUND

Q. WHAT IS PACIFICORP'S FINAL RESOURCE PROPOSAL?

A. PacifiCorp concluded its evaluation of the bids received in the Wind RFP in February 2018, and identified four wind resources as its final shortlist resulting from that RFP as its final resource proposal in this case.[2] In response to the Wind RFP issued September 17, 2018, PacifiCorp received bids for development of approximately 18 different wind projects.[3] Of the 18 projects, 14 were located in Wyoming and only four sites were located outside of Wyoming. Most of these 18 projects, however, were disqualified by the Company due to transmission queue position issues, which will be discussed below. Accordingly, other than the Company's benchmark resources, only one independent Wyoming wind project had a low enough queue position to be considered by the Company as having a viable bid.[4]

Q. DID PACIFICORP PERFORM AN UPDATED BENEFITS STUDY BASED UPON ITS FINAL RESOURCE SELECTION?

A. Mr. Link performed an updated benefits study which contains numerous adjustments relative to the analysis presented previously in this proceeding, most of which were designed to make the benefits of the Combined Projects appear more attractive. The latest benefits analysis presented in this case was in Mr. Link's Corrected Second Rebuttal and Supplemental Direct testimony filed in this docket on February 23, 2018.

Q. WHAT LEVEL OF BENEFITS DID PACIFICORP PROJECT WITH RESPECT TO THE COMBINED PROJECTS?

A. Based upon its nominal revenue requirement studies, PacifiCorp alleges the Combined Projects will result in a cost to ratepayers of $127,416,419 in the low gas price scenario, a

---

[2] In addition to the wind resources included in PacifiCorp's significant energy resource decision, PacifiCorp also seeks approval of its voluntary resource decision to build the Transmission Projects.

[3] Utah IE Report, Page 49, Table 10.

[4] Oregon IE Report, Page 34.

benefit to ratepayers of $166,548,586 in the medium gas price scenario, and a benefit to ratepayers of $499,249,164 in the high gas price scenario.[5]

I disagree that these numbers accurately reflect the actual costs and/or benefits ratepayers will experience if the projects are approved, and I expect the projects to be detrimental to customers. Notwithstanding, even if one were to agree with PacifiCorp's modeling assumptions, the wide range of outcomes shows that the Combined Projects are extraordinarily risky to ratepayers.

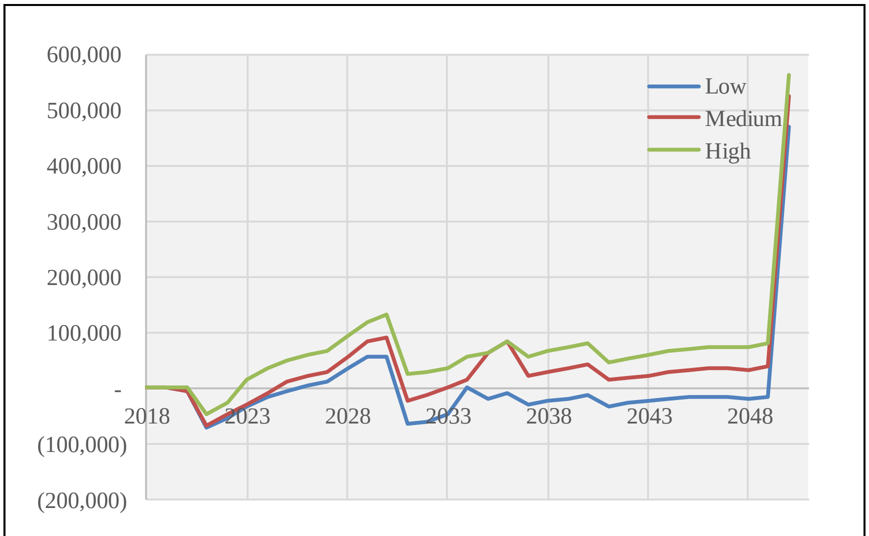
Q. DOES THE TIMING OF THE ALLEGED BENEFITS CONTRIBUTE TO THE OVERALL RISKINESS OF THE PROJECTS?

A. Yes. It's not just the variability of the alleged benefits that make PacifiCorp's proposal a risky project to ratepayers, but also the distant timing of when those alleged benefits might materialize. The benefits profile alleged by PacifiCorp is very much concentrated toward the end of the study period, as can be noted in Figure 1, below.

[5] These numbers assume a Medium CO2 policy projection. The values are derived from the Company's workpapers. See also Supplemental Direct and Rebuttal Testimony of Rick T. Link – CORRECTED, page 31 Table 3-SD. Note that the corresponding values in Table 3-SD are $158,827,011 in the low gas price scenario, $151,243,331 in the medium gas price scenario and $453,406,161 in the high gas price scenario. The amounts reported Table 3-SD appeared to be based on older modeling scenarios, so the values from the workpapers were used here.

FIGURE 1

Nominal, Total-Company Benefit/(Cost) Profile of Combined Projects by PacifiCorp Gas Price Scenario, Medium CO2 ($000)



NPVRR	Low Gas	Medium Gas	High Gas
2018 - 2027	(-)$ 117,222	(-)$ 77,960	$ 65,665
2018 - 2037	(-)$ 134,580	$ 55,567	$ 311,190
2018 - 2049	(-)$ 175,689	$ 112,586	$ 441,062
2018 - 2050	(-)$ 127,416	$ 166,549	$ 499,249

Q. WHY IS THERE A LARGE INCREASE IN BENEFITS IN THE FINAL YEAR OF THE STUDY PERIOD?

A. The increase at the end of the study period represents a new terminal value assumption that PacifiCorp incorporated into its modeling since filing its Direct Testimony. I discuss that issue further below. However, it is important to point out, with respect to Figure 1, that including the terminal values requires the y-axis to be expanded making it more difficult to see the year-to-year benefit/(cost) profile in the years prior to 2048.

Q. WHAT DOES FIGURE 1 SHOW?

A. In addition to reviewing the timing of the claimed benefits, Figure 1 also details the estimated net present value of the Combined Projects, measured over various timeframes, based on the Company's modeling. As can be seen, even in PacifiCorp's model, the

Combined Projects are expected to increase rates over the first ten years of the study period under a medium gas, medium CO2 scenario. Thus, a key question with respect to PacifiCorp's benefits study is: If the Combined Projects will cause rates to increase over the next ten years, how reliable are the estimates of the benefits in the distant time periods of the modeled study period? Quite simply, I do not believe that PacifiCorp should be gambling with such significant sums of ratepayer money on speculative benefits not anticipated to materialize for many years.

III. ISSUES IDENTIFIED IN THE RFP PROCESS

Q. IS THE WIND RFP CURRENTLY UNDER APPEAL?

A. Yes. The Wind RFP is currently under appeal before the Utah Court of Appeals in Appellate Case No. 20170967-CA. While I will not and cannot predict its outcome, the appeal creates uncertainty with the Combined Projects that will not be resolved before the conclusion of this matter.

Q. DID YOU REVIEW THE INDEPENDENT EVALUATOR REPORTS ASSOCIATED WITH THE PROPOSED RESOURCE PROCUREMENT?

A. Yes and no. Two independent evaluators ("IEs") oversaw the Wind RFP process—Merrimack Energy Group, Inc. on behalf of the Public Service Commission of Utah and Bates White Economic Consulting on behalf of the Oregon Public Utility Commission. I have reviewed their respective reports filed in their respective states. Both IEs questioned the reasonableness of PacifiCorp's resource selection in the Wind RFP, as well as issues surrounding the fairness and competitiveness of the Wind RFP. With respect to the Solar RFP process, the independent evaluator was London Economics, who has yet to issue a report with respect to the Solar RFP. London Economics was scheduled to issue that report on March 30, 2018, although that report has not been yet been filed with this Commission as of the time of writing this testimony.

Q. DO YOU AGREE WITH THE CONCLUSIONS OF THE IE REPORTS IN THE WIND RFP?

A. While I agree with many of the issues identified in the IE reports and with some of the conclusions, I do not agree with the ultimate conclusions of those reports. Particularly, I disagree with conclusory statements such as "[t]he IE is of the opinion that PacifiCorp's selection of the final shortlist of 4 projects totaling 1,311 MW was a reasonable selection *based on the constraints identified*."[6] From a ratepayer perspective, the *constraints identified* are too significant to be ignored.

Q. WHAT ISSUES DID THE INDEPENDENT EVALUATORS IDENTIFY WITH RESPECT TO THE WIND RFP?

A. The independent evaluators have documented at least three problems associated with the RFP process. I'll discuss each of these in the sub-sections that follow. First, both IEs expressed concerns, and surprise, with the way PacifiCorp applied the transmission interconnection queue in making its final resource selections. Second, both IEs noted that the bids received in the solar RFP had the potential to be more cost competitive than the Combined Projects. Third, both IEs noted that PacifiCorp adopted last minute modeling changes that had the effect of favoring utility ownership bids. As a result of these problems, I do not agree that the Wind RFP has resulted in the lowest reasonable cost resource.

---

6 Utah IE Report, Page 84 (emphasis added).

a. The Generation Interconnection Queue Influenced the Wind RFP Selection

Q. HOW DID THE GENERATION INTERCONNECTION QUEUE INFLUENCE THE WIND RFP SELECTION?

A. PacifiCorp's generation interconnection queue includes over 5,000 MW of generators seeking interconnection behind the TOT 4A cut-plane, in the transmission constrained area where PacifiCorp proposes to build the new Gateway Segment D2. Pursuant to its tariff, PacifiCorp Transmission is required to grant generator interconnection requests in serial queue order. Late in the process of making the resource selection in the Wind RFP, PacifiCorp took a position that it was required to grant interconnection requests in serial queue order and that, therefore, only those Eastern Wyoming resources with a sufficiently low interconnection queue position could be selected in the RFP process. PacifiCorp's position on this issue—that transmission capacity is assumed to be held in reserve for each bid in the interconnection queue—meant that bids with queue positions whose capacity when added to the capacity of the higher-queued bids exceeded the incremental transmission capacity provided through Gateway sub-segment D2 were disqualified, irrespective of whether those resources were lower cost or risk relative to the higher-queued bids.

Q. WHEN DID PACIFICORP INFORM THE INDEPENDENT EVALUATORS OF ITS POSITION WITH RESPECT TO THE INTERCONNECTION QUEUE?

A. It appears that PacifiCorp's position with respect to the interconnection queue was not communicated to the IEs until January 31, 2018, after best and final pricing had been received.[7] Both independent evaluators had no previous knowledge of PacifiCorp's position, and were surprised when PacifiCorp announced it.

Q. WERE THE INDEPENDENT EVALUATORS CONCERNED WITH PACIFICORP'S NEW POSITION ON THE INTERCONNECTION QUEUE?

A. Yes. In a phone conference two days later, the independent evaluators "expressed some frustration that the bid selection process ended up being limited to selection of only those projects with favorable queue positions," and that "[a]ll other proposals submitted were behind the interconnection queue constraint and would have no chance of being selected."[8]

Q. HOW WERE THE HIGHER QUEUE RESOURCES DISQUALIFIED?

A. The mechanics of the manner in which resources with lower queue positions were disqualified were described in the Oregon IE Report as follows:

> The net result of these adjustments calls for consideration of the overall context of the RFP. Recall that in its RFP as originally drafted, PacifiCorp proposed to select only projects from the constrained area and offered three benchmark projects. Based on the final [transmission] analysis... only one other third party bid on the shortlist (the [CONF] project) could even compete with these offers. In fact, only one other Wyoming wind offer — the [CONF] wind proposal — had a high enough queue position to be viable. So this entire RFP really boiled down to two viable benchmarks and two third-party offers, meaning a lot of the analysis presented here was of questionable value.
>
> To be clear, the remaining viable offers were competitive offers, but were not the best the market could provide based on cost or risk, but [the best] for the [new] transmission constraint issue.[9]

The Oregon IE noted that, as a result of the interconnection queue issue raised by PacifiCorp in January of 2018, "a majority of offers are no longer viable without

---

7 Utah IE Report, Page 63-64.

8 Utah IE Report, Page 67.

9 Oregon IE Report at 34-35.

transmission investment."[10] The Oregon IE identified three projects that "are only viable because they are outside the constrained area in Wyoming," and noted that "[i]nside the constraint *only* three projects . . . are viable."[11]

Q. IS PACIFICORP'S APPLICATION OF THE INTERCONNECTION QUEUE CONSISTENT WITH ITS OPENING TESTIMONY?

A. No. PacifiCorp did not disclose its position with respect to the application of the interconnection queue either when it filed its request for approval of the Wind RFP in Utah on June 16, 2017, or when it issued the Wind RFP on September 27, 2017.

In my opinion, it was not appropriate for PacifiCorp to omit this critical component from all discussion in the period leading up to the issuance of the RFP and only to inform parties of its intentions with respect to the interconnection queue after the bidding had been completed. In fact, PacifiCorp implied just the opposite when it made statements regarding its expectation for a robust RFP process, such as the following: "[t]housands of megawatts of Wyoming wind resource capacity are currently seeking interconnection service from PacifiCorp's transmission function, suggesting adequate and increasing wind development activity in Wyoming to support a robust response to the 2017R RFP."[12] If it was PacifiCorp's original intention to prosecute the interconnection queue through the Wind RFP process, then it had an obligation to indicate so when it filed its opening testimony and when it issued the Wind RFP.

---

10 Oregon IE Report at 35.

11 *Id*. (emphasis added).

12 Ut.PSC Docket No. 17-035-23, Supplemental Testimony of Rick T. Link lines 296-299.

Q. IS PACIFICORP'S FINAL TREATMENT OF TRANSMISSION COSTS CONSISTENT WITH ITS COMMUNICATIONS TO BIDDERS IN THE PERIOD LEADING UP TO THE ISSUANCE OF THE RFP?

A. No. In Q&As from the May 31, 2017 pre-issuance bidders conference, PacifiCorp affirmatively stated that "[c]osts associated with providing the transmission capacity in order to relieve existing congestion and facilitate the interconnection and integration of new wind projects will not be assigned to an individual project as part of the RFP evaluation."[13] Yet, that is not how PacifiCorp ultimately undertook the RFP. As the Utah IE noted "the studies found that bids with a queue position of Q0713 or higher triggered the requirements for Energy Gateway South. As a result, the SO model could essentially only select the projects that were actually selected based on their position in the queue."[14] That is, contrary to what PacifiCorp previously stated to bidders, "costs associated with providing the transmission capacity in order to relieve existing congestion and facilitate the interconnection and integration of new wind projects" ***was*** directly assigned to the individual projects with interconnection queue positions of Q0713 or higher. For bidders with interconnection queue position Q0712 or lower, such interconnection costs were not directly assigned to the project.

Q. DIDN'T PACIFICORP AGREE TO ELIMINATE THE REQUIREMENT THAT BIDDERS IN THE WIND RFP MUST HAVE A COMPLETED SYSTEM IMPACT STUDY?

A. Yes. Originally, PacifiCorp drafted the RFP such that only resources with a completed System Impact Study ("SIS") could compete in the Wind RFP.[15] Both UAE and

---

13 UAE Exhibit 3.3.

14 Utah IE Report at 82.

15 Report of the Utah Independent Evaluator Regarding PacifiCorp's Draft Renewable Request for Proposals at 35 (Aug. 11, 2017).

Interwest filed comments opposing the requirement for a SIS, on the basis that such a requirement would make the RFP uncompetitive. The Utah IE shared the concerns of UAE and Interwest, and PacifiCorp ultimately agreed to revise the Wind RFP to remove the requirement that bidders have a completed SIS.

Q. WAS THE RFP MORE COMPETITIVE AS A RESULT OF ELIMINATING THE REQUIREMENT FOR A SIS?

A. No. Ultimately, as a result of PacifiCorp's application of the generation interconnection queue, removing the requirement for a SIS did not open the RFP to any additional competition. The threshold queue position of Q0712 was made on October 9, 2015, and there were many subsequent resources in the queue with a completed SIS. Thus, eliminating the requirement for a SIS was not helpful since, as a result of PacifiCorp's position on the interconnection queue, the elimination of the SIS requirement did not expand the set of resources eligible to be selected in the Wind RFP. At a minimum, PacifiCorp had an obligation to disclose that removing the SIS requirement would make no difference due to the way it planned to implement the generation interconnection queue.

Q. WAS IT APPROPRIATE FOR PACIFICORP NOT TO DISCLOSE ITS POSITION ON THE INTERCONNECTION QUEUE WHEN IT FILED THE WIND RFP?

A. No. It certainly is possible that PacifiCorp did not realize the queue position would be the deciding factor when it initially conceived the Wind RFP. If true, however, that is simply an indication that PacifiCorp unintentionally designed an uncompetitive RFP. Whatever the case may be, representations of a robust RFP process have proved to be false. The fact that, in the period leading up to the Wind RFP, PacifiCorp undertook efforts to secure development rights for those resources—which were among the only resources with a low enough queue position to be selected—suggests that PacifiCorp probably had formed its position on the interconnection queue well before it filed the RFP.

Q. DO YOU AGREE WITH PACIFICORP'S POSITION ON THE INTERCONNECTION QUEUE?

A. No. PacifiCorp has imposed this requirement based upon its interpretation of its OATT and FERC regulation. Accordingly, I believe PacifiCorp's position is fundamentally a legal question and I am not an attorney. Notwithstanding, my understanding of the RFP as represented by PacifiCorp and as I described above, was that all viable Wyoming wind resources would be considered, that PacifiCorp's goal was to acquire the lowest cost resources available to serve load, and that therefore PacifiCorp's interconnection queue would not bias the decision making one way or another. Thus, I was under the impression that all Wind RFP bids would be scored or evaluated on the same basis, with the Company being able to then either equalize or mitigate the bidding advantage otherwise available to a bidder with a higher queue position. Such a pro-active step by the Company seems all the more important, where otherwise it seems to have advantaged itself with better queue positions for its own wind resources than for some of the lower cost competitors.

Q. WHAT IS THE SIGNIFICANCE OF PACIFICORP'S APPLICATION OF THE INTERCONNECTION QUEUE TO THE SOLICITATION PROCESS?

A. PacifiCorp's application of the interconnection queue in this manner is significant for several reasons. First, PacifiCorp did not notify the bidders, the IE, the parties, or the Commission that it would apply the interconnection queue in this manner when it sought approval of the solicitation process. Whether the Commission would have approved the solicitation process had it known of this limitation, or whether the Commission would have required modifications to the solicitation process, is unknown. And because the bidders, the IE, the parties, and the Commission were not notified of the interconnection queue cut-off during the Wind RFP approval process, we will never know.

Second, the application of the interconnection queue essentially eliminated from consideration any bid within the constrained area in Wyoming with a queue number higher than Q0712.[16] As a result, only one third-party project was able to compete with PacifiCorp's proposed Benchmark projects.[17] As noted by the Oregon IE, "this entire RFP really boiled down to two viable benchmarks and two third-party offers, meaning a lot of the analysis presented here was of questionable value."[18]

Third, in the Utah Commission docket regarding approval of the solicitation process itself, the Utah IE testified that approval of the RFP was appropriate in part because the Commission could terminate the RFP at certain "off-ramps" or "go or no-go" decision points.[19] The Utah IE indicated one such "off-ramp" "is the response of bidders. If there is not a robust response from bidders resulting in little or no competition for the

---

[16] *See* Oregon IE Report at 33 ("[I]n effect, any bid within the constrained area in Wyoming with a higher queue number than 712 would require extensive new transmission investment to be deliverable and would likely not be deliverable by the end of 2020.").

[17] *Id.* at 34-35 ("Recall that in its RFP as originally drafted, PacifiCorp proposed to select only projects from the constrained area and offered three Benchmark projects. Based on the final analysis laid out above, only one other third party bid on the shortlist . . . could even compete with these offers. In fact, only one other Wyoming wind offer . . . had a high enough queue position to be viable.")

[18] *Id.* at 35.

[19] *See* Rebuttal Testimony of Wayne J. Oliver at lines 243-85, filed Sept. 13, 2017 in Utah PSC Docket 17-035-23, *In the Matter of the Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources*.

Benchmark options, this could be one basis for terminating the solicitation process."[20] The application of the interconnection queue limitation in this process eliminated nearly all of the competition for the Benchmark options. As a result, had the queue requirement been disclosed, the limited number of qualified bidders would have triggered one of the key decision points described by the Utah IE as justifying a termination of the solicitation process.

Q. WERE THERE MORE COST EFFECTIVE ALTERNATIVES AVAILABLE THAN THE RESOURCES SELECTED IN THE REVISED FINAL SHORT LIST?

A. Since PacifiCorp applied incremental transmission costs to the bids whose queue position exceeded the incremental transmission capacity, the resources with lower queue positions had no way of being selected by the model. As a result, the degree to which one of these lower queued resources might be more cost effective than the Combined Projects is not known. Notwithstanding, Table 13 in the Highly Confidential Utah IE's report filed February 2018 in this docket shows that there were clearly better alternatives than those selected in the Final Short List. For example, Table 13 shows that thousands of megawatts of wind projects were available through PPA agreements with comparable costs, but lower risk to Utah ratepayers.[21]

Q. WHY WOULD PPA OPTIONS PROVIDE LOWER RISKS IN THIS INSTANCE?

A. As has been described in my testimony and that of others, the Combined Projects carry risks related to schedule including escalating costs and diminished PTC availability. In the build to transfer agreements ("BTAs") ratepayers are not clearly protected from these

---

[20] *Id*. at lines 270-72.

[21] *See* Highly Confidential Final Report of Merrimack Energy Group, Inc. to Utah Public Service Commission, dated February 2018 at Table 13.

risks or RMP's economic assumptions should they prove to be inaccurate. These risks are not present with a PPA. With PPAs, the developers carry the risk of cost-overruns because the developer is compensated only through a fixed $/MWh payment without regard to the cost to build the project. Similarly, with PPA options ratepayers do not bear the risk that PTCs might be unavailable, due to changes in tax laws or failure to meet the IRS safe harbor requirements. The capacity factor risk of PPAs is also lower because if the wind does not materialize at the level forecast, the ultimate payments to the counterparty will decline along with the reduced production of the project.

Q. IS THE RESULT OF THE WIND RFP SUFFICIENT GROUNDS TO DENY PACIFICORP'S APPLICATION?

A. Yes. Although I am not an attorney, I understand that a resource selection must, among other things, comply with the requirements of the Energy Resource Procurement Act and must likely result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to the retail customer. The selection process seemed biased and not in accordance with the Wind RFP. There were potentially lower cost and/or lower risk alternatives available, which were summarily disqualified based on their interconnection queue position. As a result, I believe the RFP was deeply flawed, and it is not appropriate to grant a pre-approval for a sub-optimal utility plant selected through such a process.

b. More Cost-Effective Solar Resources Were Available Through the Solar RFP

Q. PLEASE PROVIDE SOME BACKGROUND ON THE SOLAR RFP.

A. When this Commission approved the RFP at issue in this matter, it strongly suggested (but did not require) that PacifiCorp include solar resources in the RFP.[22] PacifiCorp declined to include solar resources in this RFP, but issued a separate Solar RFP that is not before this Commission for approval. That Solar RFP was issued on November 15, 2017, approximately two months after issuing the Wind RFP. Because of the timing of the issuance of the two RFPs, the Solar RFP is on a schedule that is slightly delayed relative to the Wind RFP. The Company received best and final pricing from solar bidders in mid-February, and finalized the shortlist selection process in mid-March. Based upon the concerns of the independent evaluators, PacifiCorp prepared solar sensitivity studies to compare the economics of the Solar RFP short list with the Combined Projects, as discussed in Mr. Link's supplemental testimony.

Q. WHAT DID THE SOLAR SENSITIVITIES SHOW?

A. The issuance of separate RFPs for solar and wind makes it impossible to compile the necessary evidence in this docket to form an apples-to-apples comparison between the wind and solar bids received in the respective processes. Notwithstanding, the solar sensitivity studies showed that the final bids received in the Solar RFP were lower cost and lower risk than the final short list in the Wind RFP.

---

[22] *See* Order Approving RFP With Suggested Modification, filed September 22, 2017 in Utah PSC Docket. 17-035-23.

Q. WHY DOES THE ISSUANCE OF A SEPARATE RFP PROCESS FOR SOLAR RESOURCES MAKE IT IMPOSSIBLE TO FORM AN APPLES-TO-APPLES COMPARISON BETWEEN WIND AND SOLAR BIDS RECEIVED IN THE SEPARATE RFPs?

A. The Commission noted in its Order approving the Wind RFP that a second and separate RFP for solar resources "would not accomplish the objective of comparing the proposed solar resources against the wind resources in an equal basis."[23] I agree. There are many factors that must be considered in order to make a rational decision about the relative costs, benefits and risks of wind and solar resources. Since the Solar RFP is a separate process, however, a comprehensive body of evidence does not exist in this docket to consider whether solar resources might better meet the public interest requirements of the Energy Resource Procurement Act. Based on the evidence that is available through the solar sensitivity studies, the indications are that the Solar RFP produced a lower cost, lower risk set of resources.

Q. DID THE INDEPENDENT EVALUATOR OFFER STATEMENTS CONSISTENT WITH THIS POINT?

A. Yes. The Utah IE issued a statement in his report indicating that the separate nature of the RFPs prevents a determination as to what resources are the lowest-cost, lowest-risk resources. Specifically, the Utah IE concluded that "[s]ince PacifiCorp's solicitation is based solely on the solicitation for system wind resources, it is not possible to determine if other resources would have been included in a final least cost, least risk system portfolio, potentially displacing one or more wind resources."[24] The Utah IE also stated that "it is not possible to determine if the wind-only resources offer the lowest reasonable

---

23 *Id*. at 9.

24 Utah IE Report, Page 84.

cost without an integrated resource procurement and evaluation process that also includes solar and potentially other resources."[25] These statements confirm that the least-risk and most cost-effective set of resources cannot be selected as contemplated by the Utah statutes and rules.

Q. HOW MUCH SOLAR CAPACITY WAS INCLUDED IN THE FINAL SHORT LIST FOR THE SOLAR RFP?

A. Approximately 1,419 MW measured on nameplate capacity. That is a significant amount of resources, particularly given the lack of demonstrated resource need.

Q. WHAT DID PACIFICORP'S SOLAR SENSITIVITY STUDIES SHOW?

A. When viewed in PacifiCorp's nominal study, the solar bids are overwhelmingly more cost effective than the new wind. The purported nominal benefit of the Combined Projects was just $166,548,587 in the nominal revenue requirement studies presented in Mr. Link's Supplemental Direct Testimony, under the medium gas, medium CO2 scenario. In comparison, the modeling of the final shortlist from the Solar RFP produced a nominal revenue requirement benefit of $424,128,293 in the same medium gas, medium CO2 scenario. Thus, the solar projects produced nominal benefits that were approximately 2.5 times greater than the Combined Projects, when viewed in the medium gas, medium CO2 scenario.

Q. WERE THE SOLAR SENSITIVITIES BENEFICIAL UNDER THE LOW GAS PRICE SCENARIO?

A. Yes. Not only was the solar short list more beneficial, the benefits were also more durable across price policy scenarios. PacifiCorp forecasts that ratepayers will recognize benefits from the Solar RFP final short list even in the low gas, zero carbon price policy

---

[25] *Id.* at 71.

scenario. In the low gas, zero carbon price policy scenario, the solar sensitivity study showed that the final short list from the Solar RFP would provide nominal ratepayer benefits of $216,524,070. In contrast, ratepayers would suffer an economic *loss* of $183,651,193 from the Combined Projects in the low gas, zero carbon price policy scenario. The solar RFP final shortlist also consisted entirely of PPA bids, making them less risky than the Combined Projects from that perspective, as well (as described above).

Q. DID PACIFICORP'S STUDY IDENTIFY MATERIAL BENEFIT FROM ACQUIRING BOTH THE WIND AND SOLAR PROJECTS?

A. No. If both the solar and the new wind is constructed, the PVRR(d) increased to only (-) $435,346,313 in the medium gas price scenario. This means that the incremental benefit of investing $2.2 billion in the Combined Projects was only (-) $11,218,020 in the nominal studies. Considering size of the investment, and the associated risk, the incremental nominal benefits of doing both sets of projects cannot be considered to be material.

Q. HOW DOES THE SOLAR RFP IMPACT THE WIND RESOURCE DECISION?

A. Given the results of the Solar RFP resources, the Commission should deny PacifiCorp's application for approval of the Wind Projects because other renewable resources are likely available with lower cost and lower risk, even in PacifiCorp's studies.

c. PacifiCorp Made Last Minute Modeling Changes that Had the Effect of Favoring Utility Ownership

Q. PLEASE DESCRIBE THE MODELING CHANGES THAT PACIFICORP MADE WHEN MAKING THE FINAL SHORTLIST.

A. PacifiCorp made at least two fundamental modeling changes late in the RFP process, which had the impact of making the utility ownership bids appear more attractive. First, PacifiCorp changed the way that it considered production tax credits in its "levelized" revenue requirement study by considering those benefits on a nominal, rather than a levelized basis, over a 20-year study period. The change to the treatment of production tax credits did not impact the "nominal" revenue requirement studies. Second, PacifiCorp included a new terminal value calculation that purported to increase the relative benefit of the Combined Projects.

Q. WHY DO THE NOMINAL AND LEVELIZED STUDIES PRODUCE SUCH DIFFERENT RESULTS?

A. Understanding the difference between the "levelized" studies identified in CORRECTED Table 2-SS and the "nominal" studies identified in CORRECTED Table 3-SS is important when considering PacifiCorp's benefits. In my view, the "levelized" studies are not properly considered levelized studies at all, since they include a mismatch of both levelized and nominal costs. In contrast, the nominal study simply considers all costs on a nominal basis, and is a more straight-forward approach.

Q. DO YOU AGREE WITH PACIFICORP'S PROPOSAL TO CONSIDER THE PRODUCTION TAX CREDITS ON A NOMINAL BASIS?

A. Conceptually, I don't necessarily disagree that it is appropriate to consider production tax credits on a nominal basis. However, if those benefits are considered on a nominal basis, then all costs, including the cost of the transmission, should be considered on a nominal basis. In performing its levelization analysis, the Company performs a bizarre methodology for its transmission investment, which has the effect of simply ignoring a great deal of the costs that ratepayers will be responsible for with respect to the transmission investment. The problems with PacifiCorp's transmission levelization assumptions were discussed beginning on page 48 of my Direct Testimony, and I remain concerned with that issue. Notwithstanding, if production tax credits are to be considered on a nominal basis, it is more appropriate to consider all costs and benefits on a nominal basis, rather than mismatching incongruous levelized and nominalization assumptions in the same study.

This change to the treatment of production tax credits was also at issue in Docket No. 17-035-39, regarding PacifiCorp's wind repowering proposal. In that proceeding, Mr. Higgins testified on behalf of UAE noting that "[b]y changing the method for valuing PTCs without also changing the method of valuing capital costs, the Company is effectively "cherry-picking" the combination of valuation methods that achieves the most favorable optics for the projects."[26] I agree with this statement.

Q. DO YOU AGREE WITH PACIFICORP'S NEW TERMINAL VALUE ASSUMPTION?

A. I do not necessarily disagree that there might be some longer term value with respect to a utility owned wind site, in contrast to a power purchase agreement. Notwithstanding, if a longer-term terminal value is to be included for a Company-owned site, the Company must also consider all of the ongoing capital maintenance and investment that is required with respect to that site to identify an appropriate terminal value.

Q. DOES PACIFICORP'S ANALYSIS INCLUDE ALL ONGOING CAPITAL MAINTENANCE AND INVESTMENT IN ITS TERMINAL VALUE ASSUMPTION?

A. No. While there was some consideration of capital maintenance with respect to the Wind Projects, in response to UAE Data Request 5.4, PacifiCorp stated that its analyses did not consider the ongoing capital maintenance and replacements of the Transmission Projects. Since the ongoing capital was not considered, I do not believe it is appropriate to include a terminal value component in the benefits study PacifiCorp presented. In the alternative,

[26] Docket No 17-035-39, Response Testimony of Kevin C. Higgins at 54-57

the ongoing capital investment in the Transmission Projects must be included. The Company's terminal value calculations also do not consider the cost of the Transmission Projects after the 30-year study period, which also need to be considered in the economic analysis.

Q. WHAT WAS THE IMPACT OF THE TERMINAL VALUE ASSUMPTION?

A. As can be seen in Figure 1, above, the approximate impact of the terminal year revenue requirement ranges from $48.3 million to $58.2 million.

Q. HOW DOES THAT COMPARE TO THE COST OF ONGOING CAPITAL MAINTENANCE FOR THE TRANSMISSION PROJECTS?

A. The ongoing capital cost of the transmission investment is significant in the study period. PacifiCorp is correct that the rate of replacements associated with the Transmission Projects will be low in the early years of the study period. To address this concern, I estimated replacement costs in the study period assuming a rate of retirement corresponding to a 60-R3 survivor curve, which is the current curve used for Account 356, conductors and devices. I also assumed a cost of replacement equal to 100 percent of the original cost of the investment with no adjustment for inflation. I input the resultant capital schedule into PacifiCorp's model and the result was a reduction to the PVRR benefits of approximately $91,951,462 in the 30-year study period.

In the terminal period, the increasing level of capital investment will eventually overtake depreciation expense with respect to the Transmission Projects. Based on the capital schedule described above, including those terminal costs further reduces the PVRR in the medium gas, medium CO_2 case by $18,296,839.

IV. OTHER MODELING FLAWS

Q. IN YOUR DIRECT TESTIMONY, YOU IDENTIFIED A NUMBER OF PROBLEMATIC ASSUMPTIONS IN PACIFICORP'S ANALYSIS. DO THOSE PROBLEMS PERSIST IN THE MODELING USED TO JUSTIFY THE RFP SHORT-LIST RESOURCES?

A. Yes. The RFP selection process continues to be based on a number of unreasonable assumptions, which were identified in my direct testimony. In its Rebuttal Testimony, filed on December 12, 2017, PacifiCorp discussed many of these assumptions, but its testimony on the matter is not persuasive. In fact, economic benefits studies presented in PacifiCorp's final economic screens in the latest PacifiCorp update contained even more problematic assumptions.

Q. WHAT IS THE IMPACT OF THESE PROBLEMATIC MODELING ASSUMPTIONS?

A. Table 1 below details the impact of the problematic modeling adjustments that I have identified, including the issue related to ongoing transmission capital investment costs, discussed above.

TABLE 1

Impact of Contested Modeling Adjustments

		Nominal PVRR(d) $
Company Purported Net Benefits / (Cost)		**166,548,587**
Modeling Adjustments:		
Ongoing Transmission Capital	(90,175,496)	
OATT Transmission Revenues	(25,674,149)	
EIM Unistructed Imbalance	(22,925,985)	
EIM 300 MW Link	(43,416,002)	
Total Modeling Adjustments		**(182,191,632)**
Combined Project Net Benefits / (Cost) (Before Market Change)		(15,643,045)
Approx. Impact of Declining Market Prices		(88,313,593)
Combined Project Net Benefits / (Cost) After Market Adjustment		**(103,956,638)**

a. PacifiCorp Has Not Considered that Forward Market Prices Have Declined

Q. HAS PACIFICORP ADEQUATELY RESPONDED TO CHANGING MARKET CONDITIONS?

A. No. While PacifiCorp has made a number of modeling changes to improve the overall economics of its project, it has ignored changing circumstances surrounding market prices, a key driver of the economic case for its proposal. PacifiCorp's argument for why it should be permitted to spend $2.2 billion to build the Combined Projects is premised largely on PacifiCorp's claim that the Combined Projects will lower costs for ratepayers versus the status quo of purchasing front office transactions to acquire power for the next 30 years. However, forward market price projections have declined relative to the forward prices included in PacifiCorp's economic analysis used to justify the Combined Projects.

Q. HOW DOES PACIFICORP DEVELOP ITS LONG-TERM OFFICIAL FORWARD PRICE CURVE ("OFPC")?

A. The forecasting methodology PacifiCorp uses to develop its OFPC was described in detail in PacifiCorp's response to UAE Data Request 3.2.[27] Effectively, there are three parts to PacifiCorp's forecast methodology. The first 72 months, the forecast relies on market forwards based on quotes from brokers. This initial 72 months is often referred to as the *short-term* portion of the OFPC. The subsequent 12 months (months 73 through 84) are a transition period that transitions between market forwards and a third-party fundamentals-based forecast. Beginning in month 85, the OFPC relies on a third-party forecast that PacifiCorp receives in one of its ongoing subscription services for multi-client, *off-the-shelf*, fundamentals-based forecasts. The part of the curve that relies on a third-party forecast is often referred to as the *long-term* portion of the OFPC.

Q. WHAT IS THE TENOR OF THE FORWARD PRICE CURVE PACIFICORP USED IN ITS ECONOMIC ANALYSIS?

A. In response to UAE Data Request 5.17, PacifiCorp noted that the economic analyses presented in the Corrected Second Supplemental Direct Testimony of Mr. Link used PacifiCorp's December 2017 Official Forward Price Curve ("OFPC").[28] As noted in my January 16, 2018 Rebuttal Testimony, that OFPC was issued on January 2, 2018. Notwithstanding, the long-term portion of the December 2017 OFPC was based on a long-term natural gas forecast dated November 21, 2017, as noted in PacifiCorp's response to UAE Data Request 3.2 in Docket No. 17-035-40.[29] Thus, the long-term

---

[27] UAE-UIEC Exhibit 3.1

[28] *Id.*

[29] *Id.*

market price projections did not consider the effects of tax reform or the reduction in forward market prices that occurred in late 2017.

Q. HAS PACIFICORP RECEIVED MORE RECENT THIRD-PARTY FORECASTS?

A. Yes. In UAE Data Request 5.18, UAE requested that PacifiCorp provide the long-term natural gas price forecasts that PacifiCorp has received through the third-party subscription service over the period January 1, 2018 through the present. The most recent price forecast of [redacted], as well as the prices from PacifiCorp's December 2017 OFPC, can be seen in Confidential Figure 3, below.

CONFIDENTIAL FIGURE 3

<u>Henry Hub Forward Price $/MMBtu</u>

<u>PacifiCorp December 2018 OFPC versus most recent third-party forecast.</u>

[redacted]

As can be seen from Confidential Figure 3, the more recent projections have declined, and are more in-line with current short-term forward market prices.

Q. WHAT IS THE IMPACT OF DECLINING MARKET PRICE OF NATURAL GAS ON PACIFICORP'S PROPOSAL?

A. To estimate the impact, I also performed an analysis that interpolated between the low and medium gas price scenario based upon the degree to which the February prices tended towards the low gas, zero CO2 scenario. Based on that analysis, I determined that prices were approximately 25% closer to the low gas, zero CO2 scenario, implying an impact of $88,313,593 associated with the lower curve. Since the system will redispatch around the lower market prices, I view this value to be a reasonable estimate of the lower expected forward prices.

Importantly, this market adjustment is appropriately applied even before considering the largely academic issue of whether a risk premium is embedded in forward prices. Contrary to Mr. Link's Rebuttal Testimony, I never testified to the Oregon Public Utility Commission regarding an expectation for a negative risk premium.

Mr. Link is entitled to his opinion on whether a risk premium exists, but based on my experience, market prices have consistently been lower than the utilities' long term forecasts. The data presented in my Direct Testimony is evidence of that fact. Whether it's a risk premium, or just bad forecasting, the historical data justifies placing greater weight on the low gas price scenarios. Since consideration of a risk premium would render the projects even more uneconomical to ratepayers, I did not consider that adjustment in Table 1, above.

b. PacifiCorp Incorrectly Attributes Wholesale Transmission Revenues to the Combined Projects

Q. DOES PACIFICORP'S FINAL BENEFITS STUDY CONTINUE TO INCLUDE FAULTY ASSUMPTIONS WITH RESPECT TO WHOLESALE TRANSMISSION REVENUES?

A. Yes. As noted in my Direct Testimony, PacifiCorp continues to assume that 12% of the Transmission Projects, and 12% of the associated network upgrades will be funded by PacifiCorp's Open Access Transmission Tariff ("OATT") customers. The 12% amount is based on the portion of transmission revenue requirement that has historically been funded by OATT customers. PacifiCorp has assumed that the portion of transmission revenue requirement allocated to its retail customers, including Utah ratepayers, will not increase as a result of constructing the Combined Projects.

Q. WHAT DID PACIFICORP SAY IN REBUTTAL TESTIMONY ON THIS ISSUE?

A. Very little. Mr. Vail provided a high-level description of PacifiCorp Transmission's transmission revenue requirement ("ATRR"), and then went on to state that "[t]he 12 percent figure represents the current level of ATRR funded by OATT customers."[30]

Q. DO YOU AGREE?

A. I do not dispute that the 12% figure represents the current level of ATRR funded by OATT customers. I do, however, disagree with PacifiCorp's assumption that the 12% figure will remain constant after the Combined Projects are placed into service. As a result of the way transmission costs are allocated, that percentage will decline as a result of constructing the Combined Projects. Correspondingly, the percentage of ATRR funded by PacifiCorp's retail customers, including Utah ratepayers, will increase. Mr. Vail never responded to the concern that the percentages will change.

---

30 Supplemental Direct and Rebuttal Testimony of Rick Vail lines 750-770.

Q. IS MR. VAIL CORRECT THAT THE PORTION OF TRANSMISSION REVENUE REQUIREMENT FUNDED BY RETAIL CUSTOMERS WILL NOT INCREASE?

A. No. Mr. Vail's description of PacifiCorp's formula rate overlooks the way that costs are allocated between point-to-point and network integration transmission customers. Because the Combined Projects displace resources delivered through point-to-point transmission and replaces them with resources delivered through network integrated transmission, the allocation of transmission revenue requirement to PacifiCorp's merchant function will increase as a direct result of the construction of the Combined Projects. Thus, the 12% figure cited in Mr. Vail's testimony will decline, the portion of PacifiCorp's ATRR to be paid by PacifiCorp's retail customers will increase, and the calculated benefits of the Combined Projects will decrease.

If PacifiCorp constructs the Wind Projects, the effect will be to increase the load served by network resources and reducing the loads served by front office transactions through point-to-point transmission. While PacifiCorp's network service load will increase, resulting in an increase in allocated cost, PacifiCorp still has to pay for the full capacity of the point-to-point transmission that it holds in reserve to deliver front office transactions to load, irrespective of whether it actually acquires those front office transactions. PacifiCorp has indicated that it has no intention of terminating any of its point-to-point transmission rights as a result of constructing the Combined Projects, accordingly its allocation will increase.

Q. DID MR. VAIL ADEQUATELY RESPOND TO THE RISK THAT THE TRANSMISSION PROJECTS WILL BE ASSIGNED ENTIRELY TO PACIFICORP MERCHANT?

A. No he did not. Further, there continues to be a real risk that third party OATT customers will not be willing to pay for the cost of any of the Transmission Projects, and that the costs of the economic investment will be directly assigned to PacifiCorp's merchant function.

Q. WHAT IS THE IMPACT OF DECLINING THIRD-PARTY REVENUES?

A. Third-party revenues are a key component to PacifiCorp's benefits study. And if the Wind Projects are constructed the impact of the Wind Projects on PacifiCorp Merchant's share of transmission revenue requirement is easily determined. Based upon projected 2017 net revenue requirement of $438,765,673, construction of the Transmission Projects—with a first year gross revenue requirement of [redacted]—will produce a transmission rate increase of approximately 17.7%. As a result of the Wind Projects, however, the network load of PacifiCorp's merchant function will increase by the average energy produced by the Wind Projects—approximately 450 MW per month—with no corresponding reduction to the point-to-point transmission rights PacifiCorp holds in reserve to deliver front office transactions. As a result, the total billing determinants will increase from 13,875 to 14,325 on a 12 CP basis, but PacifiCorp's share of the billing determinants will also increase by about 450 MW. Based on these values, I estimate that the portion of revenue requirement funded by OATT customers would decline from the 12% value to approximately 11.62% and the portion of revenue requirement funded by PacifiCorp's retail customers would increase accordingly.

While the 0.38% difference may seem small, the impacts are material on the overall benefits alleged by PacifiCorp, since it applies to overall revenue requirement. Based on annual transmission revenue requirements of approximately $516,629,044, the 0.38% difference equates to approximately $1,9634,190 million per year, which over a 30-year study period results in an additional present value cost of $25,674,149.

c. PacifiCorp Improperly Considered the Costs and Benefits of the Energy Imbalance Market.

Q. PLEASE DESCRIBE THE EIM BENEFIT ASSUMPTION INCLUDED IN PACIFICORP'S MODELING.

A. In response to UAE Data Request 5.9, PacifiCorp confirmed that the economic analyses in the Supplemental Direct Testimony of Rick T. Link included a modeling assumption it refers to as an "Energy Imbalance Market ("EIM") Benefit."[31] In both the System Optimizer and PaR models, the transmission topology[32] includes a new 300 MW transmission link between Jim Bridger and Walla Walla. This new transmission link does not exist today and PacifiCorp has no plans to build it. Notwithstanding, PacifiCorp believes that this incremental 300 MW of transmission capability will be made available when Idaho Power joins the EIM. Within its models, this assumption has the effect of reducing congestion out of Wyoming at Bridger (the terminating end of the proposed Gateway sub-segment D2) and increasing the purported economic benefits of the short list resources identified in the Supplemental Direct Testimony of Rick T. Link.

---

31 UAE-UIEC Exhibit 3.1

32 For an illustration of the transmission topology used in the IRP see PacifiCorp, *2017 Integrated Resource Plan*, Page 147, Figure 7.2.

Q. DID YOU EXPRESS CONCERNS WITH THIS 300 MW LINK IN YOUR DIRECT TESTIMONY?

A. In Direct Testimony, I testified that the EIM does not operate in a way that allows a utility to effectuate firm transmission of electricity, as PacifiCorp has modeled with respect to its EIM benefit adjustment.[33] In contrast, my view was that the EIM is likely to result in a net cost to Wyoming wind resources, since those resources will be subject to uninstructed imbalance charges, which PacifiCorp acknowledged was not considered in its economic analysis.[34]

Q. HOW DID THE COMPANY RESPOND?

A. In Rebuttal Testimony, PacifiCorp never actually responded to the propriety of including the unconstructed 300 MW transmission link between the Jim Bridger and Walla Walla. Mr. Link apparently disagreed with the way I characterized the Supplemental GRID studies that were prepared as a part of the 2017 IRP.[35] He noted that the GRID model studies were only used in the 2017 IRP, and not in subsequent analyses presented in this docket.[36] I, however, acknowledged that PacifiCorp only used the Supplemental GRID studies in the 2017 IRP, and that PacifiCorp had since incorporated the adjustments into the SO and PaR models.[37] The only reason that the Supplemental GRID studies were considered was due to the fact that, as can be noted in PacifiCorp's response to UAE Data Request 5.9, PacifiCorp has been unwilling to isolate the impact of the 300 MW link between Jim Bridger and Walla Walla (which, again, has not been built and

---

33 Direct Testimony of Bradley G. Mullins, page 41, line 15 – page 43, line 20.

34 Id.

35 Rebuttal Testimony of Rick Link, lines 1333 - 1340.

36 *Id.*

37 Direct Testimony of Bradley G. Mullins, page 41, line 15 – page 43, line 20.

PacifiCorp does not plan to build) in economic studies performed using the SO and PaR models. Since PacifiCorp has been unresponsive, the Supplemental GRID studies are the best information available estimating the economic impact of the unconstructed 300 MW transmission link between Jim Bridger and Walla Walla included in PacifiCorp's economic analyses related to the Combined Projects.

Further, in response to the argument that the EIM is likely to represent an additional ancillary service cost through the imposition of instructed imbalance charges, Mr. Vail testified that "there is no basis to assume that uninstructed imbalance will result in a net cost and, in fact, the expectation is that over time there will be no net impact associated with uninstructed imbalance"[38] Mr. Vail did not, however, provide any supporting data—such as actual uninstructed imbalance charges for existing Wyoming wind resources—to support his claim that the uninstructed imbalance of Wyoming wind resources will net to zero.

Q. DID PACIFICORP CONFIRM THAT IT DID NOT CONSIDER ANY UNINSTRUCTED IMBALANCE CHARGES IN ITS BENEFITS STUDY?

A. Yes. Mr. Vail's Supplemental Direct Rebuttal Testimony confirmed that the economic studies presented in the Supplemental Direct Testimony of Mr. Link in support of the Combined Projects did not consider *any* ancillary service costs associated with acquiring EIM imbalance services applicable to the Wind RFP short list wind resources.

---

[38] Rebuttal Testimony of Rick Vail, lines 711 - 717.

Q. WHAT DID PACIFICORP'S RESPONSE TO UAE DATA REQUEST 5.14 SHOW?

A. It showed that Mr. Vail was wrong. The uninstructed imbalance has tended to be positive for wind resource currently located in the transmission-constrained area of Wyoming. Confidential Table 2, below, shows the historical values.

CONFIDENTIAL TABLE 2

Uninstructed Imbalance Costs for Wind Projects

[redacted]

Based on the actual experience of wind resources located in eastern Wyoming, I estimate that the annual imbalance costs associated with the 1,311 MW Wind Projects will be material. I estimate that on an annual basis that cost will be $1,770,692, as detailed in Confidential Table 2, above.

Q. BASED ON THIS HISTORICAL DATA, HOW MUCH UNINSTRUCTED IMBALANCE DO YOU EXPECT FOR THE WIND PROJECTS?

A. Based on the average $/MWh of these historical levels, incorporating these imbalance charges will reduce the benefits of the Combined Projects by approximately $22,925,985 over the 30-year study period.

Q. WHAT IS THE IMPACT OF THE 300 MW TRANSMISSION LINK?

A. I continue to disagree with PacifiCorp's inclusion of the unconstructed 300 MW transmission link in its economic analysis supporting the Combined Projects. Inclusion of a firm 300 MW transmission link is not consistent with the operation of the EIM, which does not provide a utility with firm transmission rights, as assumed in PacifiCorp's analysis. In UAE-UIEC Exhibit 3.1, in response to UAE Data Request 5.11, PacifiCorp confirmed that PacifiCorp does not assert that it can "use the EIM to achieve new, firm transmission rights on another EIM participants' system," as modeled with respect to the 300 MW transmission link. Based on the supplemental GRID studies, presented in the IRP, grossed up for the higher level of wind PacifiCorp has proposed through the final short list, I estimate the impact of this 300 MW link to be an approximate $43,416,002 reduction to the net present value revenue requirement benefits PacifiCorp has alleged.

V. PACIFICORP DOES NOT HAVE A NEED FOR NEW RESOURCES

Q. ARE THE WIND PROJECTS, AND ASSOCIATED TRANSMISSION, NECESSARY TO PROVIDE ELECTRICAL SERVICES TO UTAH CUSTOMERS?

A. No. Central to this case is whether the constructing combined projects are necessary to provide reliable, low-cost electrical services to Utah customers. As noted in my Direct Testimony, nothing presented in this case demonstrates that the Combined Projects are necessary utility investments. To the contrary, the most recent resource needs assessment presented on page 91 and 92 of PacifiCorp's 2017 IRP do not show a need for the addition of any capacity for the entirety of the ten year period of analysis.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp continues to argue that because it has yet to execute the front office transactions, that those should not be considered in its resource need. I continue to disagree. Having access to bilateral markets is very valuable, and it is not prudent for PacifiCorp to disregard that market access when considering its resource adequacy. Just because the prices are uncertain does not mean that the market should be excluded when considering the adequacy of existing resources.

Q. HAS PACIFICORP PREVIOUSLY TAKEN THE POSITION THAT THE AVAILABILITY OF FRONT OFFICE TRANSACTIONS MEANS THAT IT DOES NOT HAVE A RESOURCE NEED?

A. Yes. In Utah PSC Docket 15-035-53,[39] PacifiCorp filed an application requesting that the Commission reduce the PPA term for Qualifying Facilities from 20 years to 3 years. PacifiCorp attempted to justify the request on the grounds that PacifiCorp's 2015 IRP demonstrated that PacifiCorp did not need additional generation resources because of the Company's ability to acquire power through front office transactions.[40]

---

39 *See In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Utah PSC Docket 15-035-53.

40 *See, e.g.*, Direct Testimony of Paul Clements at lines 55-56 ("PacifiCorp's 2015 IRP, which was filed in March 2015, shows no new resource is required until 2028."); *id*. at 62-63 ("The Company has no need for resources in the next decade."); *id*. at lines 167-170 ("[I]t is extremely rare for a utility to voluntarily enter into a 20-year fixed-price energy contract without a specified energy resource need due to concerns about price risk, market liquidity, and other risk considerations."); *id*. at lines 372-374 ("Long-term resource needs are typically identified in the IRP only after lower-cost, lower-risk resource opportunities are exhausted such that a long-term resource is required to meet customer load requirements.").

Q. HAS PACIFICORP UPDATED ITS LOAD FORECAST SINCE THE 2017 IRP?

A. Yes. In response to UAE Data Request 5.6, PacifiCorp provided its most recent load forecast. PacifiCorp did not, however, identify the tenor of that load forecast. Notwithstanding, the load forecast has declined dramatically since the issuance of the 2017 IRP. In 2026, peak loads are forecast to be down by approximately 14% or 1,525 MW, relative to the 2017 IRP. This can be observed in Table 3, below.

CONFIDENTIAL TABLE 3

<u>Impact of Most Recent Load Forecast (Coincident Peak, MW)</u>

[redacted]

Q. HOW DOES THIS DECLINING LOAD IMPACT PACIFICORP'S RESOURCE NEEDS?

A. In Confidential UAE-UIEC Exhibit 3.2, I update the results of PacifiCorp's resource needs assessment in Table 5.14 from the 2017 IRP, changing nothing but the load forecast to be consistent with the Company's response to UAE Data Request 5.6. As the exhibit shows, even before considering front office transactions, PacifiCorp is forecast to be in a capacity surplus position of 526 MW in 2026. With front office transactions, that surplus position grows to 2,196 MW. Thus, with the declining load forecast, PacifiCorp's concerns about whether front office transactions should be considered in evaluating resource needs is moot.

Q. WHAT DOES THAT MEAN WITH RESPECT TO PACIFICORP'S RESOURCE PROPOSAL?

A. Ratepayers are already in a tenuous position of having more resources than needed, and building the Combined Projects will only exacerbate that problem.

Q. HAS THE COMPANY PREPARED AN UPDATED RESOURCE NEED ASSESSMENT WHEN CONSIDERING THE RFP RESOURCES?

A. In UAE Data Request 5.1, UAE requested that PacifiCorp confirm that it has not performed an updated resource needs assessment when selecting the RFP resources. In its response, the Company stated that it has not performed an updated needs assessment. Finally, PacifiCorp noted that it planned to issue an IRP update on March 31.

Q. DID PACIFICORP FILE ITS IRP UPDATE ON MARCH 31, 2018?

A. No. Accordingly, the only resource needs assessment available is from the 2017 IRP and that assessment did not show any resource needs in the first ten years of the study period. And, in fact, after updating for the most recent load forecast, it is apparent that PacifiCorp's resource length will grow to uncomfortable levels, even without considering the Wind Projects. Accordingly, I continue to recommend that the request be denied on the basis that there has not been a clearly demonstrated resource need, with or without wholesale market transactions.

VI. RISK OF NEW TRANSMISSION TECHNOLOGY

Q. HAS PACIFICORP CHANGED THE TRANSMISSION TOWER TECHNOLOGY THAT IT IS PROPOSING WITH RESPECT TO THE TRANSMISSION PROJECTS?

A. Yes. Rather than using the steel lattice transmission towers described in PacifiCorp's opening testimony, the Company is now proposing to use an untested, undeveloped technology.

Q. WHAT IS THIS NEW TECHNOLOGY?

A. It is not clear from Mr. Vail's testimony. Mr. Vail noted, however, that PacifiCorp "decided it could use a new tower design that would significantly reduce the structures' weight, and therefore cost, as compared to the tower design used in other segments of the Energy Gateway project."[41]

Q. HAS PACIFICORP FINISHED DEVELOPING THIS NEW TECHNOLOGY?

A. No. Mr. Vail indicated that design and testing is still underway with respect to the new technology.

Q. HAS RELIANCE ON NEW TECHNOLOGIES RESULTED IN SIGNIFICANT COST OVER-RUNS FOR OTHER UTILITIES IN THE PAST?

A. Yes. When building the One Nevada ("ON") Line, NV Energy used "advanced electric transmission towers." Notwithstanding, the towers were unable to withstand sustained winds, and accordingly, testing and mitigation measures had to be undertaken, which delayed operation over one year and increased costs by $42.5 million.

---

[41] Supplemental Direct and Rebuttal Testimony of Rick A. Vail, lines 114 – 123.

Q. DOES USE OF A NEW TOWER DESIGN PRESENT AN ADDITIONAL RISK ASSOCIATED WITH THE TRANSMISSION LINES NOT COMING IN ON BUDGET?

A. Yes. This issue with respect to the new transmission tower technology is just one of many risks that may cause PacifiCorp to go over budget on the transmission line. The need to meet safe harbor requirements to obtain the full value of production tax credits means that this sort of risk has the potential to be very costly with respect to the Combined Projects. Further, given the state of the economic justification, any such risks will only make the Combined Projects even more uneconomical to ratepayers. Mr. Vail acknowledges that the Populous to Terminal transmission line was originally forecast to cost only $78 million, but ultimately cost $801 million. He might disagree with the relevance of the $78 million estimate, and the reasons that the Idaho Public Utilities Commission relied on that original estimate when disallowing a major portion of the Populous to Terminal transmission line, but Mr. Vail never disagrees that there is a real risk that it might not be possible to construct the Transmission Projects within the proposed budgets. As noted in my Direct Testimony, even a 15% overage on capital costs would eliminate any notion of benefits in PacifiCorp's modeling.

Q. IS THE FAILURE TO CONSIDER THIS RISK A REASON NOT TO APPROVE PACIFICORP'S APPLICATION?

A. Due to PacifiCorp's failure to adequately consider these risks, it is not appropriate to approve the Transmission Projects under the Energy Resource Procurement Act.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

UAE-UIEC EXHIBIT 3.1

April 17, 2018

17-035-40 / Rocky Mountain Power
March 9, 2018
UAE Data Request 5.1

UAE Data Request 5.1

Reference the February 16, 2018 Second Supplemental Direct Testimony of Rick T. Link, lines 6 through 10: Please confirm that PacifiCorp did not prepare an updated resource needs assessment when developing the economic analysis identified in the referenced testimony? Please provide an explanation for PacifiCorp's response.

Response to UAE Data Request 5.1

The Company assumes that "resource needs assessment" refers to the Company's 2017 Integrated Resource Plan (IRP) Volume I, Chapter 5 (Load and Resource Balance). Based on the foregoing assumption, the Company responds as follows:

No, the Company did not prepare an updated needs assessment relevant to the second supplemental direct testimony filing. Resource need is an endogenous consideration of every System Optimizer model (SO model) and Planning and Risk (PaR) model run, in which the models are identifying the optimal least-cost, least-risk means to meet all system requirements. To the extent that the Company has updated loads, prices, resources parameters, etc., "resource need" has been automatically updated in the models.

The Company will include an updated load and resource balance assessment in its 2017 IRP Update, to be filed with the Public Service Commission of Utah (UPSC) on March 31, 2018.

17-035-40 / Rocky Mountain Power
March 9, 2018
UAE Data Request 5.3

UAE Data Request 5.3

Reference the Second Supplemental Direct Testimony of Rick T. Link at lines 68 through 78: When preparing the nominal and levelized revenue requirement calculations, what assumptions did PacifiCorp make with respect to the termination of the Power Purchase Agreement (PPA) portion of Cedar Springs facility (i.e. did PacifiCorp assume that the PPA portion would be renewed, and if so, at what price.)?

Response to UAE Data Request 5.3

The Company assumed the contract terminates at the termination date. The Company did not assume the automatic renewal of power purchase agreements (PPA) in the Second Supplemental direct testimony filing. This is consistent with the treatment of contracts, including PPAs and qualifying facilities (QF), in the 2017 Integrated Resource Plan (IRP).

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.4

UAE Data Request 5.4

Reference the Second Supplemental Direct Testimony of Rick T. Link, lines 81 through 85: Do PacifiCorp's nominal or levelized revenue requirement analyses consider the impacts of ongoing capital additions to, and replacements of, the proposed Aeolus-to-Bridger/ Anticline D.2 transmission facilities. If no, please explain why the cost of those ongoing capital additions and replacements have been excluded.

Response to UAE Data Request 5.4

PacifiCorp's revenue requirement analyses does not consider any ongoing capital additions or replacements for the proposed Aeolus-to-Bridger/Anticline D.2 transmission facilities. The Company does not project the need for incremental post-construction capital additions or replacements across the transmission system caused by the Aeolus-to-Bridger/Anticline transmission line. PacifiCorp's economic analysis does includes operation and maintenance (O&M) costs of $1 million per year in 2017 dollars.

17-035-40 / Rocky Mountain Power
March 9, 2018
UAE Data Request 5.5

UAE Data Request 5.5

Please provide a copy of PacifiCorp's most recently completed depreciation study, along with the final rates by FERC account and sub-account that have been approved by the Utah Public Service Commission.

Response to UAE Data Request 5.5

Please refer to Attachment UAE 5.5-1, which provides the most recent depreciation study filed with the Public Service Commission of Utah (UPSC) on January 22, 2013 in Docket 13-035-02.

Please refer to Attachment UAE 5.5-2, which provides a copy of the stipulation associated with that filing which provides the final rates approved by the UPSC.

17-035-40 / Rocky Mountain Power
March 9, 2018
UAE Data Request 5.6

UAE Data Request 5.6

Please provide PacifiCorp's most recently completed long-term load forecast, with hourly loads, and including all time periods considered in the forecast.

Response to UAE Data Request 5.6

Please refer to Confidential Attachment UAE 5.6, which provides the most recently completed hourly, system-level long-term load forecast.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rule 746-1-602 and 746-1-603.

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.9

UAE Data Request 5.9

Reference the Supplemental Direct and Rebuttal Testimony of Rick T. Link at lines 1336 through 1340: Mr. Link states that "[t]he GRID studies and assumptions referred to by Mr. Mullins were used in the 2017 IRP, but not in the economic analysis included in this case"

(a) Does PacifiCorp agree that, in preparing the economic analyses identified in the February 16, 2018 Second Supplemental Direct Testimony of Rick T. Link, it has incorporated the adjustments underlying the referenced supplemental GRID studies into the System Optimizer and Planning and Risk models?

(b) Does the PacifiCorp have any basis to conclude that the impacts of the adjustments underlying the supplemental GRID studies have changed materially after being incorporated into System Optimizer and Planning and Risk models? If yes, please provide all studies showing what PacifiCorp believes the impact of those adjustments to be when incorporated into the System Optimizer and Planning and Risk models.

(c) Does PacifiCorp's economic analysis identified in the Second Supplemental Direct Testimony of Rick T. Link still include an assumption that the transfer capability between Jim Bridger and Walla Walla is increased by 300 MW corresponding to growing participation in the Energy Imbalance Market ("EIM")? If yes, please provide PacifiCorp's best estimate of the impact of this assumption on the medium gas and medium CO2 scenario. If no, please explain.

(d) Does PacifiCorp's economic analysis identified in the Second Supplemental Direct Testimony of Rick T. Link still include an assumption that the Wyoming loads are reduced to account for purported line loss benefits of the Transmission Projects? If yes, please provide PacifiCorp's best estimate of the impact of this assumption on the medium gas and medium CO2 scenario. If no, please explain.

(e) Does PacifiCorp's economic analysis identified in the Second Supplemental Direct Testimony of Rick T. Link still include an assumption to account for reduced de-rates associated with constructing the Transmission Projects? If yes, please provide PacifiCorp's best estimate of the impact of this assumption on the medium gas and medium CO2 scenario. If no, please explain.

Response to UAE Data Request 5.9

(a) PacifiCorp does not agree. The line loss, reliability and energy imbalance market (EIM) assumptions adopted in the 2017 Integrated Resource Plan (IRP) were previously evaluated in the Generation and Regulation Initiative Decision Tool (GRID). In the 2017 IRP, PacifiCorp applied the results from these GRID studies into the portfolio costs used to analyze the new wind and transmission projects. In the economic analysis presented in this proceeding, including the economic analysis

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.9

summarized in the Company's second supplemental direct testimony filing, these assumptions were subsequently incorporated in the System Optimizer model (SO model) and the Planning and Risk (PaR) model. Consequently, no results from GRID have been used in the Company's economic analysis presented in this case.

(b) PacifiCorp has not isolated the incremental impact of referenced assumptions in the SO model and PaR model. Please refer to the Company's responses to DPU Data Request 4.3, DPU Data Request 4.13, DPU Data Request 4.14, and OCS Data Request 10.1, which provide information related to the referenced assumptions.

(c) Yes. Please refer to the Company's response to subpart (b) above.

(d) Yes. Please refer to the Company's response to subpart (b) above.

(e) Yes. Please refer to the Company's response to subpart (b) above.

17-035-40 / Rocky Mountain Power
March 30, 2018
UAE Data Request 5.10 – 1st Supplemental

UAE Data Request 5.10

Is PacifiCorp required to submit independently balanced EIM Base Schedules for PACE and PACW balancing area pursuant to the CAISO's EIM tariff or PacifiCorp Transmission's EIM tariff? If yes, please provide a citation to the tariff corresponding to the requirement. If no, please explain how the EIM base schedules are determined for the respective balancing areas.

1st Supplemental Confidential Response to UAE Data Request 5.10

Further to the Company's response to UAE Data Request 5.10 dated March 15, 2018, PacifiCorp continues to object to this request as not reasonably calculated to lead to the discovery of relevant or admissible evidence. Without waiving this objection, PacifiCorp now responds as follows:

PacifiCorp submits a balanced schedule for both of its balancing authority areas (BAA) separately, but these schedules consider the resource positions in both the PacifiCorp East (PACE) and PacifiCorp West (PACW) BAAs. For example, PacifiCorp will schedule the [redacted] which is in the PACW BAA, into the PACE BAA to facilitate energy transfers for economic or reliability purposes. Similarly, PacifiCorp will schedule energy or reserves to the PACW BAA from resources in the PACE BAA if it is economic or for reliability reasons. The final balanced schedules that are submitted for the PACE and PACW BAAs are "independently" balanced, but they use resources across both BAAs.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rule 746-1-602 and 746-1-603.

17-035-40 / Rocky Mountain Power
March 30, 2018
UAE Data Request 5.11 – 1st Supplemental

UAE Data Request 5.11

Does the EIM provide PacifiCorp with the ability to schedule firm energy between balancing areas in an amount exceeding the firm transmission rights that PacifiCorp possesses between the two balancing areas? If yes, please explain, with references to specific tariff provision, how transfers of such firm energy transfers may be accomplished.

1st Supplemental Response to UAE Data Request 5.11

Further to the Company's response to UAE Data Request 5.11 dated March 15, 2018, PacifiCorp continues to object to this request as not reasonably calculated to lead to the discovery of relevant or admissible evidence. Without waiving this objection, PacifiCorp now responds as follows:

No.

Note: the Company clarifies that the economic analysis in this docket does *not* assume that additional 300 megawatts (MW) of transmission capability that will be available when Idaho Power Company (IPC) joins the energy imbalance market (EIM) is "firm" transmission, nor does PacifiCorp assert that it can "use the EIM to achieve new, firm transmission rights on another EIM participants' system[.]".

17-035-40 / Rocky Mountain Power
March 30, 2018
UAE Data Request 5.14 – 1st Supplemental

UAE Data Request 5.14

Please provide uninstructed imbalance charges for the following wind facilities on a monthly basis (or the greatest level of granularity available) over the period January 1, 2015 through June 30, 2017:

(a) Glenrock

(b) Glenrock III

(c) Foote Creek

(d) McFadden Ridge

(e) Seven Mile Wind

(f) Seven Mile II Wind

(g) Top of the World Wind

(h) Dunlap Wind

(i) High Plains Wind

(j) Mountain Wind I

(k) Mountain Wind II

(l) Rock River I

(m) Rolling Hills Wind

1st Supplemental Response to UAE Data Request 5.14

Further to the Company's response to UAE Data Request 5.14 dated March 15, 2018, PacifiCorp continues to object to this request as not reasonably calculated to lead to the discovery of relevant or admissible evidence. Without waiving this objection, PacifiCorp now responds as follows:

Please refer to Confidential Attachment UAE 5.14 1st Supplemental, which provides the requested information for subparts (d) and (h) above.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rule 746-1-602 and 746-1-603.

17-035-40 / Rocky Mountain Power
March 9, 2018
UAE Data Request 5.17

UAE Data Request 5.17

Please identify the date that PacifiCorp issued the forward price curve used in the revenue requirement analyses in the Second Supplemental Direct Testimony of Rick T. Link.

Response to UAE Data Request 5.17

The Company's December 2017 Official Forward Price Curve, used in the revenue requirement analyses in the second supplemental direct testimony of Company witness, Rick T. Link, was issued January 2, 2018.

Accompanying scenarios, used in revenue requirement analyses, were based on projections issued by third-parties in late December 2017 and early January 2018.

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.18

UAE Data Request 5.18

Please identify and provide all long-term natural gas price forecasts that PacifiCorp has received through a third-party subscription service over the period January 1, 2018 through the present.

Response to UAE Data Request 5.18

PacifiCorp receives long-term natural gas price forecasts from two third-party subscription services for approximately thirty hubs across North America, most of which are not applicable to this proceeding. As such, please refer to Confidential Attachment UAE 5.18 for long-term natural gas price forecasts, relevant to this proceeding, received by PacifiCorp through third-party subscription services since January 1, 2018. Note: the provided third-party information is proprietary information and is provided with the permission of the third-party vendors, and is subject to the confidentiality protections noted below.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rule 746-1-602 and 746-1-603.

17-035-40 / Rocky Mountain Power
March 16, 2018
UAE Data Request 5.19

UAE Data Request 5.19

Reference the Supplemental Direct and Rebuttal Testimony of Rick V. Vail, lines 767 through 770: Mr. Vail states that “[t]he 12 percent figure represents the current level of ATRR funded by OATT customers.”

(a) Please confirm that PacifiCorp assumed that the proportion of ATRR funded by retail customers will not increase as a result of acquiring the Wind Projects and Transmission Projects? If no, please explain.

(b) Please explain how PacifiCorp Transmission ATRR costs are allocated between Network Integration Transmission Service and Point-to-Point transmission customers?

(c) Please identify billing determinants used for Network Integration Transmission Service and Point-to-Point transmission customers, and explain why the billing determinants are appropriately used for the respective services?

(d) Please identify the transmission service PacifiCorp plans to use with respect to the Wind Projects (i.e. Network Integration Transmission Service or Point-to-Point Transmission Services).

(e) Pursuant to its OATT, is PacifiCorp allowed to designate front office transactions as a network resource? If no, please explain why not, and identify the transmission service used to deliver front office transactions to load?

(f) Does PacifiCorp intend to terminate any Point-to-Point transmission rights, in the event that the Transmission Projects and Wind Projects are constructed? If yes, please identify each reservation, which PacifiCorp intends to terminate.

(g) Please explain how PacifiCorp loads served by Point-to-Point transmission are considered in the determination of PacifiCorp’s Monthly Network Load for purposes of PacifiCorp’s Network Integration Transmission Services.

(h) Does PacifiCorp agree that its Monthly Network Load will increase if the Transmission Projects and Wind Projects are constructed due to the fact that a greater portion of its load will be served by Network Resources (i.e. the Wind Projects), rather than through Point-to-Point transmission (i.e. Front Office Transactions). If no, please explain.

(i) Does PacifiCorp agree that, if its Monthly Network Load were to increase as a result of constructing the Transmission Projects and Wind Projects, and assuming no changes to reserved Point-to-Point transmission rights, that the proportion of ATRR funded by retail customers would also increase? If no, please explain.

17-035-40 / Rocky Mountain Power
March 16, 2018
UAE Data Request 5.19

Response to UAE Data Request 5.19

The Company objects to these requests as overly broad and not reasonably calculated to lead to the discovery of admissible or relevant evidence. Without waiving these objections, the Company responds as follows:

(a) The analysis assumes that the added cost of transmission is allocated based on estimates of the current allocation between retail and third-party customers. The cost of transmission is allocated between customers based on peak coincident loads, long-term point-to-point (PTP) contract capacity, and short-term reservations purchased. The allocation of transmission depends on the future mix of loads and long-term and short-term capacity. Therefore, the additional wind generation added in Wyoming does not directly correlate to additional transmission costs. These resources could be added and designated as additional network resources and optimized in real-time as part of the energy imbalance market (EIM). Therefore, no determination has been made that additional generation results in additional transmission cost.

(b) Transmission costs are allocated to transmission customers based on the customer's relative share of peak loads, long-term PTP capacity, as well as short-term reservations purchased on the Open Access Same-Time Information System (OASIS). A transmission customer with network integration transmission service is assessed transmission charges based upon the customer's load at time of the system's coincident peak.

(c) The billing determinant for network service is transmission customer network load grossed up for stated losses in PacifiCorp's Open Access Transmission Tariff (OATT). Long-term PTP transmission capacity is assessed on customer contract capacity plus the capacity loss factor as stated in PacifiCorp's OATT. These billing determinants are appropriate because they are comparable and represent the utilization of the transmission system.

(d) Network Integration Transmission Service (NITS).

(e) PacifiCorp may designate front office transactions (FOT) as a network resources provided they meet the designation requirements of the OATT.

(f) No.

(g) This question appears to assume that PacifiCorp's merchant function is utilizing on-system resources under PTP contracts to serve load in other balancing authority areas (BAA). In this case, PacifiCorp is allocated a share of PacifiCorp's transmission cost based on the capacity of these long-term PTP contract rights. PacifiCorp also pays third-party transmission service providers for load service outside of PacifiCorp's transmission system.

17-035-40 / Rocky Mountain Power
March 16, 2018
UAE Data Request 5.19

(h) No. Construction of the Transmission Projects and Wind Projects by itself and designating the resources as network resources does not alone increase PacifiCorp's Monthly Network Load. The total cost of transmission is dependent on retail consumption and the relative share of any increase or decrease in load compared to third-party transmission use. In addition, if energy is required to serve load through importing energy into PacifiCorp's BAAs then the cost of that transmission would include both the utilization of PacifiCorp's transmission as well as any third-party transmission necessary to wheel the energy to serve load.

(i) No. Construction of the Transmission Projects and Wind Projects would not alone indicate or lead to an increase in PacifiCorp's Monthly Network Load. As described in responses to other subparts, the cost of transmission is based on system loads and reservations of long-term and short-term PTP transmission.

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.20

UAE Data Request 5.20

Please identify any assumptions PacifiCorp has made with respect to the terminal value of the Wind Projects in the economic analyses identified in Second Supplemental Direct Testimony of Rick T. Link. Please include in your answer the identification of assumptions with respect to Wind Projects included in the final short list and those that were not included in the final short list.

Response to UAE Data Request 5.20

Please refer to the Company’s response to DPU Data Request 13.20.

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.21

UAE Data Request 5.21

To the extent that terminal values were included in the economic analysis identified in Second Supplemental Direct Testimony of Rick T. Link, please provide a narrative explanation of the methodology used to develop the terminal value and provide work papers supporting the calculation of the terminal value amount for each Wind Project included in the final short list and for each Wind Project that was not included in the final short list.

Response to UAE Data Request 5.21

Please refer to the Company's response to DPU Data Request 13.20.

17-035-40 / Rocky Mountain Power
March 15, 2018
UAE Data Request 5.24

UAE Data Request 5.24

Has PacifiCorp identified any terminal costs, such as decommissioning costs, associated with the Wind Projects or Transmission Projects? If yes, please explain how those additional terminal costs are considered in PacifiCorp's analysis.

Response to UAE Data Request 5.24

PacifiCorp's analysis includes removal (or decommissioning) costs associated with wind and transmission assets. Wind assets have an expected life of 30 years with removal costs assumed at $65 per kilowatt ($/kW). Transmission assets have an expected life of 62 years with removal costs of 16 percent of original cost based on the Company's most recent depreciation study. Removal costs are recovered from customers on a straight-line basis over the life of the asset. Please refer to the confidential work papers supporting the second supplemental direct testimony of Company witness, Rick T. Link, specifically folder "Transmission", file "Energy Gateway GM 2017 03 13 21% US Tax".

17-035-40 / Rocky Mountain Power
January 11, 2018
UAE Data Request 3.2

UAE Data Request 3.2

Regarding PacifiCorp's Official Forward Price Curve (OFPC) issued in the 4th quarter of 2017 on or around December 29, 2017:

(a) Please provide a copy of the referenced price curve for gas and power markets where PacifiCorp transacts and for all years where a forecast was developed.

(b) Please provide a description of how the long-term natural gas price forecast (i.e. prices developed by 3rd party consultants used in the OFPC for periods extending beyond 72 months) was developed in the referenced OFPC.

(c) Please describe any changes to the long-term natural gas forecasting methodology that occurred in developing the referenced OFPC, relative to the OFPC that was used in the August 31, 2017 Supplemental Testimony of Rick T. Link in Docket No 17-035-23

(d) Please provide any memoranda or documentation in PacifiCorp's possession describing the methodologies the 3rd party consultants used to develop PacifiCorp's long-term natural gas price forecast in the referenced OFPC.

(e) Please state when the long-term natural gas price forecasts used in the referenced OFPC were developed by the 3rd party consultants.

(f) Please identify whether the long-term price forecasts used to develop the referenced OFPC include the impact of the passage of the Tax Reform Bill.

Response to UAE Data Request 3.2

The Company understands that the term "referenced OFPC" used throughout this request is intended to reference the Company's December 2017 official forward price curve (OFPC). Based on this understanding, the Company responds as follows:

(a) Please refer to Attachment UAE 3.2-1, which provides the Company's December 2017 OFPC.

(b) The December 29, 2017 OFPC was developed using 72 months of market forwards followed by 12 months (months 73 through 84) of a forwards-fundamentals blend that transitions to a pure fundamentals-based forecast starting in month 85. Blended prices for months 73 through 84 are calculated as an average of the preceding year's forward prices with the following year's fundamentals prices on a month-by-month basis.

The fundamentals-based portion of the OPFC, starting month 85, was developed by an expert third-party forecasting service and published in nominal dollars using PacifiCorp inflation indices. The expert third-party fundamentals forecast was

17-035-40 / Rocky Mountain Power
January 11, 2018
UAE Data Request 3.2

supplied as part of the Company's ongoing subscription to receive multi-client "off-the-shelf" fundamentals-based forecasts on a regular basis.

(c) The long-term natural gas forecasting methodology used by PacifiCorp to develop the December 29, 2017 OFPC is unchanged relative to the OFPC that was used in the August 31, 2017 Supplemental Testimony of Company witness, Rick T. Link in Docket 17-035-23.

(d) Please refer to Confidential Attachment UAE 3.2-2.

(e) The long-term natural gas price forecast used in the December 2017 OFPC was produced by an expert third-party forecasting service, as part of its multi-client subscription service, on November 21, 2017.

(f) The impact of the Tax Reform Bill is not explicitly reflected in the gas price forecast, which was issued before the Tax Reform Bill was passed or signed, used in the December 2017 OFPC.

Confidential information is provided subject to Public Service Commission of Utah Rule 746-1-602 and 746-1-603.

BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

UAE-UIEC EXHIBIT 3.3

April 17, 2018

PacifiCorp 2017R RFP Pre-Issuance Bidders' Conference Questions and Answers

The following are questions and answers resulting from the PacifiCorp 2017R RFP Pre-Issuance Bidders' Conference held in Salt Lake City, Utah on Wednesday, May 31, 2017.

For additional questions, please submit them to the 2017R RFP mailbox at:

RFP_2017R@pacificorp.com

Additional information regarding the 2017R RFP is provided at the follow link which will be updated throughout the 2017R RFP process:

www.pacificorp.com/sup/rfps/2017-rfp.html

Question and Answers:

Will there be a RFP for solicitation for the Oregon IE? If so, where can the RFP be located?

The RFP for the Oregon IE was filed with the Oregon Commission on June 1, 2017. Information regarding this RFP is provided at http://www.pacificorp.com/sup/rfps/2017-rfp-or-eval.html.

Can you provide a list of attendees to this Pre-Issuance Bidders' Conference?

A list of attendees is provided at www.pacificorp.com/sup/rfps/2017-rfp.html.

We are very interested in being a part of this project as a subcontractor offering survey and materials testing. We assume that these tasks would be contractor responsibilities. If there has been a list of contractors and subcontractors created for this project we would like to be added to or told how to get on that list so that we can stay informed during the bidding process.

The 2017R RFP will be for new wind resources that will be submitted by companies that are developing wind projects in Wyoming and seeking to sell the power out of the project or the asset itself to PacifiCorp. The 2017R RFP is not a RFP for professional or construction services to a project to be constructed. The bidders may be issuing their own RFP for engineering, procurement and construction (EPC) services.

For more information on the Energy Gateway West sub-segment D2 process and vendor/contractor information, please use the following link: http://www.gatewaywestproject.com/.

Can you please confirm if projects must be located in Wyoming, Oregon, or Utah?

> We do not plan to have the requirement that project(s) be physically located in any specific state(s). We will be requiring that proposed projects must be capable of interconnecting with the PacifiCorp's Wyoming transmission system inclusive of the Energy Gateway West sub-segment D2 transmission line running from Aeolus to Bridger/Anticline, or be able to deliver energy and capacity into PacifiCorp's Wyoming transmission system.

Can you please clarify as to why the RFP must be approved by the Utah and Oregon PUCs?

> PacifiCorp is filing the RFP with the Public Utility Commission of Oregon (Oregon Commission) according to requirements under OPUC Orders No. 04-046 and 14-149. PacifiCorp is filing the RFP with the Utah Public Service Commission (Utah Commission) according to requirements under Utah's Energy Resource Procurement Act, Title 54, Chapter 17 and UPSC Rules R746-420. These rules, from both states, came out of state legislation concerning procurement of large resources and or length of term of a power purchase agreement.

Will PacifiCorp consider resources other than wind?

> Under the 2017R RFP PacifiCorp is seeking wind resources.

With respect to transmission cost associated with the Gateway D2 segment, is this considered a sunk cost or is that part of the evaluation?

> The transmission costs associated with Gateway D2 segment are not assigned to a specific project as part of the bid evaluation.

How will we evaluate transmission costs distinguished by project location?

> For the costs of the project itself, the transmission cost, other than Direct Assigned costs as identified in the interconnection studies, is not assigned to any specific project. Costs associated with providing the transmission capacity in order to relieve existing congestion and facilitate the interconnection and integration of new wind projects will not be assigned to an individual project as part of the RFP evaluation.

Under what financial metrics will the benchmark resources be evaluated?

> The financial metrics used for the benchmark resources and RFP bids will be same. These metrics will be vetted and validated by the independent evaluators as part of the draft 2017R RFP review process and be used consistently throughout the RFP.

What is the timing of the self-build EPC RFP?

As part of the 2017 R RFP, the benchmark resource team will be developing and implementing their procurement schedule separately. Currently, this process is expected to be managed on somewhat the same schedule as the 2017 R RFP taking into account that benchmarks must be submitted one week prior to the other bids.

Is the wind be targeted as part of the 2017R RFP exclusive of the wind repowering sought under the IRP preferred portfolio?

The targeted wind resources under the 2017R RFP are in addition to the wind repowering capacity described in PacifiCorp's 2017 IRP preferred portfolio.

Can you explain the difference between final shortlist and winning bids as referenced in the 2017R RFP proposed schedule?

The final shortlist will be those bids PacifiCorp has selected for contract negotiation and will be proposing to the Utah Commission to initiate process of executing agreements.

Will only Wyoming sites be considered?

No, however PacifiCorp will require demonstration that the project can be delivered to our Wyoming transmission system on a firm basis.

Will there be a separate transmission EPC RFP for the new transmission line?

Procurement efforts associated with new transmission line will be a separate project driven under the direction of and managed by the PacifiCorp transmission function.

For more information on the Energy Gateway West sub-segment D2 process and vendor/contractor information, please use the following link: http://www.gatewaywestproject.com/.

Will the Commission approved 14% wind capacity factor be applied in this RFP, and how will that impact PacifiCorp's capacity position in the future?

In PacifiCorp's 2017 Integrated Resource Plan (IRP) the summer peak capacity contribution for wind in PacifiCorp's east balancing authority area was determined to be 15.8%. This capacity contribution value is currently being proposed for application in evaluating the RFP bids and benchmark resources, subject to adjustments attributed to the project specific wind shape.

What is the timing of the new transmission line?

The new 140-mile, 500 kV transmission line is projected to be completed by December 31, 2020. This effort will be coordinated and managed by the PacifiCorp transmission function.

For more information on the Energy Gateway West sub-segment D2 process and vendor/contractor information, please use the following link: http://www.gatewaywestproject.com/.

Will the benchmark resources be self-builds or an asset purchases?

The benchmark resources will be submitted as self-build.

Will the benchmarks be limited to the 860 MW as stated in this presentation?

The benchmark resources listed in the presentation are what are currently being proposed and may change prior to final submittal into the 2017R RFP.

Does PacifiCorp plan to consider their purchases of safe harbor wind turbine equipment for the benchmarks as a sunk cost?

PacifiCorp would not consider the purchases of safe harbor wind turbine equipment as a sunk cost.