REDACTED
Rocky Mountain Power
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Surrebuttal Testimony of Joelle R. Steward

May 2018

Q. Are you the same Joelle R. Steward who previously provided testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. In support of the Company's request that the Public Service Commission of Utah ("Commission") approve its significant energy resource decision for new wind resources ("Wind Projects") and voluntary energy resource decision for construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects"), I respond to regulatory and ratemaking policy issues raised in the supplemental rebuttal and surrebuttal testimonies filed April 17, 2018, by Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Mr. Charles E. Peterson, and Mr. David Thomson, and Office of Consumer Services ("OCS") witnesses Mr. Bela Vastag, Mr. Philip Hayet, and Ms. Donna Ramas.

Q. Please summarize your testimony.

A. The Company's application for approval of the Resource Tracking Mechanism ("RTM") for interim recovery of the Combined Projects is the most reasonable approach to match the costs and benefits of the Combined Projects and provide the Company an opportunity to recover its prudently-incurred costs. Moreover, the alleged complexities of the RTM are minor compared to the alternative approaches, including deferrals and back-to-back rate cases to capture the full impact on revenue requirement.

Conditions on approval related to projected costs and benefits, proposed by several parties, are unnecessary, unprecedented, and unjustified. As previously noted in the Company's rebuttal testimony filed in January 2018, the Company has accepted the risks that are within the Company's control related to qualification for the production tax credits ("PTCs"). Additionally, both the Significant Energy Resource Approval law, Utah Code Ann. § 54-17-303 and -304, and Voluntary Request for Resource Decision Review law, Utah Code Ann. § 54-17-403 and -404, already provide substantial customer protections for potential changes in the projects that would occur during implementation, such as cost-overruns. Consistent with these laws, the Company's filing includes a soft cost cap based on the estimated costs of the Combined Projects for implementing the RTM. The Company will seek a prudence determination for any variances in excess of the current projected costs in the next rate case. If there is a major change in circumstances before construction, the Company will seek additional Commission guidance through the Order to Proceed process. Additional conditions for cost caps on capital or operations and maintenance are inconsistent with Utah's resource approval laws.

Finally, with the removal of the Uinta wind project from this application, the net rate impact for the Combined Projects' is now 1.4 percent for the first full year of operation.

RESOURCE TRACKING MECHANISM

Q. Have parties raised any new objections to the Company's proposed RTM?

A. No. For the most part, the positions and arguments raised by the parties in their supplemental rebuttal and surrebuttal testimonies reiterate positions and arguments already presented. Thus, my rebuttal testimony filed on January 16, 2018, largely addresses the issues raised in the April 17, 2018 surrebuttal testimony. I will, however, respond to further refinements to the arguments in the testimonies of Mr. Thomson and Ms. Ramas.

Q. Both Mr. Thomson and Ms. Ramas dismiss the Company's concern that there is uncertainty about approval of a future test period if a general rate case is relied upon to begin recovery of the Combined Projects instead of the RTM. (Thomson Surrebuttal and Supplemental Rebuttal, lines 18–31; Ramas Second Rebuttal, lines 91–178.) Ms. Ramas represents this as "the Company's uncertainty of its ability to present adequate evidence supporting a future test year." Do you agree with her representation?

A. No. The Company has presented substantial evidence to support future test periods in various general rate cases throughout the years and is confident it can continue to do so. Nonetheless, test period is typically a contested item in the Company's Utah rate cases. There is no guarantee that the Company will be able to use a future test period that captures the same matching of costs and benefits that the RTM would provide, or would align cost pressures into one general rate case.

Q. Mr. Thomson points to the most recent three general rate cases as evidence that it is "not highly uncertain but highly likely that the future test period would be used to capture the costs and benefits of the Combined Projects in a single, timely GRC." (Thomson Surrebuttal and Supplemental Rebuttal, lines 29–31.) Do you agree?

A. No. As acknowledged by Mr. Thomson, in two of the last three general rate cases, the test period was not contested because it was stipulated to in prior general rate case settlements. Only looking at the last three cases presents a skewed view of the litigation context for test periods in general rate cases. Table 1 below shows the history of test periods in the last 10 years of Utah general rate cases.

Table 1: Utah GRC Test Period History			
Docket No.	**Proposed Test Period**	**Contested?**	**Test Period Result**
13-035-184	June 2015	No, Stipulated	June 2015
11-035-200	May 2013	No, Stipulated	May 2013
10-035-124	June 2012	Yes, Litigated	June 2012
09-035-23	Dec 2010	Yes, Settled	June 2010
08-035-38	June 2009 (year end rate base)	Yes, Litigated	Dec 2009 (average rate base)
07-035-93	June 2009	Yes, Litigated	Dec 2008

As shown in Table 1, test period has been a contested issue in every single Utah general rate case other than those that were pre-determined in the settlement in the prior rate cases. Furthermore, in the instances where test period was contested, only one case resulted in the final test period being the one originally proposed by the Company. Since no settlement exists here, Mr. Thomson's statement that based on history it is "highly likely" the Company would be able to capture the costs and benefits in a single rate case through its proposed test period has no basis.

Q. Why do you find the OCS's position in this docket particularly troubling?

A. OCS witness Ms. Ramas dismisses the Company's proposal for the RTM to enable a proper matching of costs and benefits as unnecessary, claiming that the Company can simply "modify the anticipated timing of its next rate case and the test year utilized in that case." (Ramas Second Rebuttal, lines 154–156.) Yet, in past general rate cases, OCS has frequently opposed the Company's proposed test period. In fact, in the most recent general rate case where the test period was contested, Docket No. 10-035-134 ("2010 GRC"), OCS filed testimony proposing a forecast test period closer in time than the Company's proposed test period. As support for this argument, the OCS witness stated:

> Our test period proposal acknowledges that *new capital investment* and increases in net power costs appear to be *key drivers* underlying the Company's rate request, but it strikes an appropriate balance between ratepayers and shareholders in achieving a fair and reasonable outcome. *In particular, the Company has other cost recovery processes for major plant additions (MPA) and an energy balancing account (EBA) to address the costs of major plant investment and net power cost variations between rate cases.* (Docket No. 10-035-124, Test Period Phase Direct Testimony of Dan Gimble for the Office of Consumer Services, lines 15–59 (emphasis added).)

OCS advised the Commission in the 2010 GRC that, when selecting a test period, it should give weight to the fact that the Company has alternative avenues for cost recovery. Based on this, OCS claimed a test period that fully includes the new capital investment, a key driver in the rate case, was not necessary. But in this case, OCS is taking the opposite position—alternative avenues for cost recovery (the RTM) should not be used; instead, the Company should use a general rate case and should be able to file a reasonable test period that allows for cost recovery.

These contradictory positions are even more troubling when coupled with the fact that Ms. Ramas also calls the Company's proposal to remove the benefits of the cost-free wind generation from the Energy Balancing Account ("EBA") if the RTM is not approved "fictitious." Essentially, OCS appears to be arguing that, contrary to the normal principle that matches costs and benefits in rates, the Company should bear the costs of the Combined Projects for as long as possible, while the benefits of the generation flow through to customers in the EBA.

Q. Ms. Ramas also raises concerns that the expected timing of the Company's next general rate case with a 2021 test period would reflect base rates with the revenue requirement for the Combined Projects at its highest point until a subsequent rate case. (Ramas Second Rebuttal, lines 157–178.) Is this a valid concern?

A. No. Ms. Ramas argues that the Company should use a traditional rate case to begin recovery of the costs of the Combined Projects and questions my assertion that obtaining a future test period that would fully incorporate the Combined Projects is uncertain. But, at the same time, she criticizes the anticipated test period I identified for the Company's next general rate case, which would align several cost pressures into one case. Ms. Ramas's criticism underscores my concern that setting a future test period can be contentious and lead to the need for back-to-back general rate cases.

Q. Mr. Thomson reiterates that back-to-back rate cases have been used in the past to incorporate new significant rate base additions into base rates and concludes that "creating another mechanism in this case is unwise." (**Thomson Surrebuttal and Supplemental Rebuttal, line 62.**) **Do you agree?**

A. No. Mr. Thomson provides no reason for his conclusion that the expense, complexity, and burden of back-to-back rate cases is a better choice than establishing an RTM to match costs and benefits of a specific identifiable project as an interim measure to avoid multiple general rate cases. Because the costs and benefits of the Combined Projects can be measured and recovered through an RTM on a short-term basis, without the complexity and expense of a general rate case, all parties' resources are better used, which also benefits customers.

Q. Ms. Ramas points to the Company's cost recovery history of Cholla, Craig, Hayden, and Chehalis pointing out the Company did not receive recovery outside of a general rate case through a separate mechanism. Is this a valid reason to reject the RTM?

A. No. Once again, Ms. Ramas relies on general rate cases as the ideal venue for cost recovery. As previously stated, the Company objects to the claim by the OCS that the Company should be limited to obtain cost recovery through one or more general rate cases while the benefits of the zero-fuel-cost energy flow through to customers through the EBA. The generation plants Ms. Ramas cites were not zero-fuel-cost resources for which benefits would flow 100 percent through a fuel-cost mechanism. The fact that these resources were recovered through a general rate case does not mean that is the optimal option for recovery in this case. The Company has worked hard to limit the number of rate cases it files, recognizing the challenges that multiple rate cases can present to the Commission and the Company's customers.

Q. Did the DPU comment on your statement on lines 245–246 in your Rebuttal and Supplemental Testimony that, if a deferral is used, then the net power cost benefits of the zero-fuel-cost energy should be pulled from the EBA and deferred as well?

A. Yes. Mr. Thomson states that the DPU would not object to deferring the net power cost benefits as part of a Commission-approved deferred accounting order until the next general rate case. (Thomson Surrebuttal and Supplemental Rebuttal, lines 187–190.) Although he expresses reservations that a proper method for calculating the benefits could be difficult, the recognition that, in principle, costs and benefits should match, is a more reasonable position than OCS's. I would also note that the RTM is a simpler approach than attempting to determine a proper method for calculating the net power cost benefits to be removed from the EBA if the deferral approach is used. Nevertheless, a method for calculating the net power cost benefits was already provided in my direct testimony. Specifically, the Company proposed valuing any incremental energy from the Wind Projects using a monthly market price less wind integration. (*See* Direct Testimony of Jeffrey K. Larsen, lines 214–230.)

Q. Mr. Thomson continues to argue that, if an accounting order deferral is used, there should be no carrying charges and cites a number of examples where carrying charges were not applied to deferred accounts. (Thomson Surrebuttal and Supplemental Rebuttal, lines 65–122.) Do you agree these are reasonable precedents or support for his position in this case?

A. No. The examples of deferrals for which there was no carrying charge were all due to agreements in stipulations. As the Commission is well aware, stipulations are the outcome of a negotiation in which there is give and take among all parties. As there is no stipulation in this proceeding, and as Mr. Thomson points out, stipulations are not precedential, the comparisons are inapplicable and inappropriate in this proceeding.

Q. Does Mr. Thomson make other suggestions with regards to carrying charges?

A. Yes. Mr. Thomson states that the Commission may want to allow carrying charges on the zero-fuel-cost energy due to the fact that it is a fuel-related item. He also suggests that any deferral related to the PTC benefit should not receive a carrying charge since it is not a fuel-related item. (Thomson Surrebuttal and Supplemental Rebuttal, lines 124–132.) Mr. Thomson seems to deem fuel-cost items as being carrying-charge "eligible," while any other item is not. There are many examples of deferred accounting orders that have carrying charges that are not fuel related. Just because the EBA has a carrying charge, and Mr. Thomson can point to a few examples of deferred accounting stipulations without carrying charges, does not imply a standard that fuel-related items are worthy of a carrying charge and other deferred costs are not.

Q. What is the Company's recommendation for carrying charges?

A. The Company believes the RTM should be approved as the best way to align the costs and benefits in a timely manner with a carrying charge based on the most recently-approved Commission rate (currently 4.09 percent). The Company also recommends that if the RTM is not approved and deferred accounting is used instead, the use of a carrying charge should be consistent among *all* components of the deferral, with no special treatment of fuel-related items.

Q. Ms. Ramas states that the Company has not provided evidence that it would be unable to earn its allowed rate of return if the RTM is rejected. (Ramas Second Rebuttal, lines 151–153.) Is an earnings test an appropriate measure to determine whether to establish a mechanism for cost recovery?

A. No. The fact that the Company's most recent historical earnings may have been comparable to the Company's authorized rate of return does not mean that the Company's future earnings will be sufficient. The RTM is designed to allow the Company to match the costs and benefits of the Combined Projects and align several cost pressures into one case. The decision about whether the costs for these resources are prudent and should be included in rates is independent from other issues that would be reviewed during a general rate case; in other words, the same audit on the Combined Projects' actual costs should occur whether recovery is through the RTM or in a general rate case.

Q. Ms. Ramas again raises the argument that the shareholders will earn a return while the customers may or may not see benefits, dismissing your rebuttal that return is a normal part of a utility's cost of service. (Ramas Second Rebuttal, lines 207–262.) How do you respond?

A. Ms. Ramas's premise is that the Company's recovery of its cost of service, including a regulated return on its capital costs, is a reason the Company's request should be rejected. As I stated in my supplemental rebuttal testimony, this is contrary to basic ratemaking and the foundation of the regulatory compact. The Company does not dispute that when one adds new rate base, a higher return is earned, all else equal. But this is irrelevant to the determination of whether the Combined Projects deliver substantial customer benefits and are in the public interest. The return of and on the Company's investment is included in the Company's economic analysis, which demonstrates net benefits to customers under virtually all scenarios modeled.

Q. Mr. Peterson argues in his surrebuttal testimony that there were significant differences between the Combined Projects and the Company's acquisition of the Chehalis power plant. Do you agree there were differences?

A. Yes, there are differences, but those differences do not undermine the comparison I made. In many ways, the Combined Resources are a more compelling and less-risky investment for customers due to (1) the availability of PTCs to offset many of the costs, (2) the selection of the Wind Projects through a competitive solicitation endorsed by independent evaluators in both Utah and Oregon, and (3) the fact that the Wind Projects will provide emission-free, zero-fuel-cost energy.

RESPONSE TO PROPOSED CONDITIONS FOR APPROVAL

Q. Mr. Hayet continues to recommend that the Commission impose unprecedented conditions on approval of the Combined Projects to effectively shield customers from all risks associated with the projects. (Hayet Second Rebuttal Testimony, lines 948–981.) Has the Company's position regarding these conditions changed?

A. No. Mr. Hayet's recommendations remain entirely unreasonable and unjustified given the nature of the resource decision at issue in this case, and the provisions of Utah's resource approval laws. Again, the Combined Projects are no different in this respect from any other utility investment and do not warrant extraordinary and unprecedented conditions.

Q. DPU, OCS, and the Utah Association of Energy Users/Utah Industrial Energy Consumers claim that the Company has refused to assume any of the risk of the Combined Projects. Is this true?

A. No. First, it is my understanding that the resource decision approval statutes provide substantial customer protections under both the Significant Energy Resource Approval in Utah Code Ann. § 54-17-303 and -304, and Voluntary Request for Resource Decision Review in Utah Code Ann. § 54-17-403 and -404. Section 54-17-303(1)(a)(iii) limits cost recovery in a rate case or other proceeding to "up to the projected costs specified in the commission's order issued under Section 54-17-302." Any increase from the projected costs specified in the order must be reviewed in a general rate case. (Utah Code Ann. § 54-17-303(1)(c)). The cost recovery section in the Voluntary Request for Resource Decision Review (Utah Code Ann. § 54-17-403) provides the same protection. Notably, Section 54-17-303(1)(a)(iii) allows for recovery up to the projected costs *in either* a general rate case or other appropriate commission proceeding, while Section 54-17-303(1)(c) allows for a review of costs in excess of the projected costs in *only* a general rate case. This is entirely consistent with the Company's proposal in this case with the RTM capped at the estimated costs.

Therefore, approval of the resource decision for the Combined Projects in this application does not shield the Company from risks of cost-overruns. The Company continues to bear the risks of cost-overruns unless and until it can demonstrate prudence in a general rate case. Additionally, the Company bears the risk that if there is a change in circumstance or projected costs, it will seek a Commission review and determination on whether the Company should proceed with implementation, in accordance with Utah Code Ann. §§ 54-17-304 and -404.

Second, other than costs, the largest risk to ensure customer benefits is tied to qualifying the Wind Projects for the PTCs. As previously stated in testimony, the Company assumes the risk that the Wind Projects will qualify for the PTCs, noting the exception of factors outside of its control such as force majeure events and changes in law. (Crane Supplemental Direct and Rebuttal, lines 203–210.) What this means is that to the extent any new wind project or turbine fails to qualify for PTCs, in whole or in part other than under the noted exceptions, PTCs will be imputed to each such project based on that project's actual wind output for equipment placed in service and included in rate base at full revenue value (*i.e.*, including full gross up for federal and other applicable taxes). If there is a force majeure event or change in law during the implementation and construction of the Combined Projects, the Company will make a filing for Commission review, in accordance with Utah Code Ann. §§ 54-17-304 and -404.

Q. What are the projected costs that the Company is seeking approval of in this proceeding?

A. Confidential Table 1 shows the projected capital costs without the Uinta project and the source.

Confidential Table 1 - Calculation of Capital Costs

	In-Service Capital ($ million)	**Source**
Wind Resource Capital Costs	$1,455	Confidential Exhibit RMP__(RTL-1SS)
Interconnection Network Upgrades	$111	Confidential Exhibit RMP__(RTL-1SS)
Aeolus-to-Bridger/Anticline Transmission Line	$679	Confidential Exhibit RMP__(RTL-1SS)
Sub-Total Capital Costs as Filed	$2,245	
Remove Uinta Capital Costs	[redacted]	Confidential Exhibit RMP__(RTL-1SS)
Remove Uinta Interconnection Network Upgrades	[redacted]	Confidential Exhibit RMP__(RAV-2SS)
TOTAL Capital Costs Without Uinta	[redacted]	

Parties will have the opportunity to verify actual costs as part of the annual audit of the EBA and RTM deferred balance.

Q. Dr. Zenger is proposing that the Commission consider the status of the 2017 Protocol that expires on December 31, 2019, in reviewing the Company's request for resource approval. (Zenger Supplemental Rebuttal and Surrebuttal, lines 372–382.) Likewise, Mr. Vastag expresses concerns related to the current Multi-State Process ("MSP") and recommends that Mr. Hayet's cost caps should be adopted to address these concerns. (Vastag Second Rebuttal, lines 82–92.) Are these reasonable recommendations?

A. No. This is contrary to the 2017 Protocol currently approved for inter-jurisdictional cost allocation in the state of Utah, which uses dynamic allocation factors. Moreover, any change to inter-jurisdictional cost allocations in the future will be approved by the Commission and should not by restricted by this proceeding. In effect, Dr. Zenger and Mr. Vastag are recommending that the Commission pre-determine the outcome of the current MSP, which would be detrimental to the continuing negotiations with stakeholders throughout the Company's service area. In addition, as I previously explained in testimony, if Utah's allocated costs associated with these projects are fixed, then the benefits, including PTCs and reduced net power costs, must also be fixed. (Steward Supplemental Direct and Rebuttal, lines 365–382.) Any change of this type would require resource subscriptions that are not allowed under the 2017 Protocol and have not yet been agreed to in the MSP.

UPDATED RTM CALCULATION

Q. Have you updated the exhibits from your second supplemental testimony to reflect the costs for the Combined Projects without the Uinta wind project?

A. Yes. Confidential Exhibit RMP___(JRS-1SR)[1] reflects the updated costs and benefits in the economic analysis in Mr. Link's testimony without the Uinta project. The exhibit is in the same format used in my previous testimony as Exhibit RMP__(JRS-2SS). It calculates the annual revenue requirement and shows the overall net impact for the Combined Projects that would be reflected in rates without Uinta, including the proposed RTM.

Q. What are the updated annual estimated rate impacts associated with the Combined Projects that would be reflected in rates through the RTM, in conjunction with the EBA?

A. The Company is projecting the Combined Projects' updated annual revenue requirement impact for the years 2020 to 2023 to be in the range of ($3) million to $28 million in Utah, as shown in Table 1 of Confidential Exhibit RMP___(JRS-1SR). The net rate impact would be approximately 1.4 percent for the first full year of operation.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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[1] Exhibit RMP__(JRS-1SR), page 2, is marked confidential in order to retain the confidentiality of the Uinta project costs.