ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 West North Temple
Salt Lake City, Utah 84116

October 28, 2021

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

Re: Docket No. 21-035-42
In the Matter of Rocky Mountain Power's Application for Alternative Cost Recovery for Major Plant Additions of the Pryor Mountain and TB Flats Wind Projects
Rocky Mountain Power Rebuttal Testimony

In accordance with the Scheduling Order and Notice of Hearing issued by the Public Service Commission of Utah on August 20, 2021, Rocky Mountain Power hereby submits for filing its rebuttal testimony.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
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By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
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Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

cc: Service List Docket No. 21-035-42

CERTIFICATE OF SERVICE

Docket No. 21-035-42

I hereby certify that on October 28, 2021, a true and correct copy of the foregoing was served by electronic mail to the following:

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REDACTED
Rocky Mountain Power
Docket No. 21-035-42
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Joelle R. Steward

October 2021

Q. Are you the same Joelle R. Steward who filed direct testimony in this proceeding on behalf of PacifiCorp, d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I respond to the direct testimony of various witnesses by the Division of Public Utilities ("DPU"), Office of Consumer Services ("OCS") and Utah Association of Energy Users ("UAE").

Q. Please summarize your rebuttal testimony.

A. Utah law, specifically section 54-7-13.4 of the Utah Code ("MPA statute"), authorizes the Public Service Commission of Utah ("Commission") to approve alternative cost recovery for the major plant additions of the Pryor Mountain and TB Flats wind projects. In contrast to the arguments by the DPU, OCS and UAE, neither the statute nor the administrative rules (R746-700-30) implementing the statute preclude the Company's ability to request full cost recovery for resources that have been found to be prudent that are not in rates following the 2020 General Rate Case, Docket No. 20-035-04 ("2020 GRC").

Q. The DPU, OCS and UAE argue that the Company's requested cost recovery for the TB Flats and Pryor Mountain wind projects do not qualify under the major plant addition statute because the portion of the investments the Company is seeking to recover in this case do not exceed one percent of the Company's rate base, therefore, do not meet the definition of "major plant addition" in section 54-7-13.4(1)(c).[1] Do you agree with this interpretation?

A. No. The statute defines "major plant addition" as "any single capital investment project of …an electrical corporation that in total exceeds 1% of the …electrical corporation's rate base, based on the …electrical corporation's most recent general case determination."[2] As I explain further below, both of these projects meet the definition of a major plant addition ("MPA") because they are single capital investments over one percent of Utah's rate base and because the in-service dates were within 18 months of the Commission's rate case order in the 2020 GRC. Very simply the MPA statute allows the Commission to authorize cost recovery within these defined parameters outside of general rate cases.

Q. Dr. Powell argues: "Only additional costs should be considered. If the complete project costs can be relied on as a basis for meeting the threshold size, any incremental addition to a large project might be able to rely on the original capital cost to the meet the requirement."[3] Do you agree that the costs the Company is seeking recovery of are an "incremental addition to a large project"?

A. No. The TB Flats and Pryor Mountain projects each constitute a "single capital

[1] See Powell Direct at 102-170; Beck Direct at 16-31; Higgins Direct at 114-120.
[2] Utah Code Section 54-7-13.4(1)(c).
[3] Powell Direct at 130-133.

investment project," which is the definition of "major plant addition" under the MPA statute. The Company has not made any "incremental additions" to either project since the complete projects were considered in the 2020 GRC, and the costs the Company seeks to recover through this proceeding are part of the complete projects themselves. Dr. Powell appears to conflate the average period ratemaking treatment with the definition of total project cost. The economic analyses that support the prudence of the investments used projections for full project costs, not just the portion of the projects that would fall under an average-of-period ratemaking treatment. The costs included in this case are part of the full costs necessary to support the resource decisions that were already found to be prudent by this Commission, not additional costs to the projects or stand-alone investments. Moreover, the concern that the Company could merely rely on these project costs to seek recovery of *any* incremental addition in the future is a red herring as that is not a circumstance before the Commission in this proceeding. The Company is not correcting a forecasting error from the general rate case but seeking recovery of a material amount of investment for these projects that is not captured in current rates.

Q. UAE witness Mr. Higgins argues that these projects are already entirely included in rate base because they were included in the average-of-period test period in the 2020 GRC.[4] How do you respond?

A. The use of average-of-period for rate base in the 2020 GRC does not mean that the costs of the projects are included *in rates* in their entirety. This is demonstrated by Mr. Higgins's point that because the production tax credits ("PTC") and net power cost

[4] Higgins Direct at 114-171.

("NPC") benefits flow to customers through the Energy Balancing Account ("EBA").[5] Thus, the Company would not be getting recovery of $6.7 million in annual revenue requirement for the investment in these plants while customers would be getting the full benefits. The MPA statute provides for alternative cost recovery of these investments.

Q. OCS witness Ms. Beck notes that the Company controls what test year it proposes and states that the Company's request "subverts the test year policy."[6] Should the Commission's adoption of a calendar year 2021 test period and average-of-period ratemaking treatment in the 2020 GRC for these projects foreclose the ability to use the MPA statute for full cost recovery?

A. No. The 2020 GRC set rates based on a test period. The Commission has extensive administrative rules governing how a test period is established for a base rate change in a general rate case.[7] The MPA statute and related rule R746-700-30 are designed for recovery of costs within an 18-month window from the last general rate case.[8] Therefore, they have no limitations or requirements regarding a test period. The MPA statute considers only the costs and benefits—the net revenue requirement impacts—of the major plant addition for costs not already in rates. Moreover, one purpose of the MPA statute is to reduce the need for back-to-back rate cases by allowing a utility to obtain full cost recovery of major plant additions. The MPA statute balances rate case timing with in-service dates for major capital investments through a limitation of

[5] Higgins Direct at 92-94.
[6] Beck Direct at 33-34, 40-41.
[7] R746-700-10, -22, and -23.
[8] See Beck Direct at 36-38 (describing the purpose of the MPA statute to "eliminate the need for full rate review when it has been done recently").

18 months following a rate case order. Accordingly, arguments that the Company is or would be misusing the MPA statute by not just immediately filing another rate case or absorbing the costs are unpersuasive.

Q. Mr. Higgins argues that this filing "is an attempt by RMP to circumvent the normal results of ratemaking when using average rate base."[9] Further he argues, "any mismatch is solely the side effect of tracker mechanisms developed and advocated by the Company in pursuit of its broader corporate objectives."[10] How do you respond?

A. Mr. Higgins ignores the fact that the EBA statute and the MPA statute are directives adopted by the state legislature, regardless of his personal feelings about them or any advocacy by the Company or any other stakeholder. While he may believe alternative cost recovery is outside "normal ratemaking" the fact remains that the MPA statute exists as an available tool for the Company to fairly recover its costs. Mr. Higgins' interpretation of the statutes to allow for customers to receive the full benefits of capital additions through the EBA without paying the full cost is convenient, but it is not supported by the purpose of the EBA and MPA statutes or good ratemaking principles.

Q. DPU argues that the Company's proposal to change base EBA rates in this proceeding is inconsistent with its position in the 2020 GRC.[11] Is this correct?

A. No. The context of the Company's statements in the 2020 GRC is important. In the Company's rebuttal testimony quoted by Dr. Powell, the Company was simply clarifying its proposal to use actual revenue rather than forecasted revenue in the EBA

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[9] Higgins Direct at 242-243.
[10] Id. at 246-248.
[11] Powell Direct at 180-238.

deferral filings in response to an apparent misunderstanding of the DPU's witness. Mr. Webb was not speaking to changes to the EBA during an MPA proceeding like this one. Similar to a general rate case, the MPA statute authorizes the Commission to "adjust rates" as a result of an MPA filing, which would include adjustments to the Base EBA.[12]

Q. Why is an update to the Base EBA appropriate as part of this proceeding?

A. The MPA statute explicitly requires the Commission to consider "savings and benefits" associated with the major plant additions and authorizes recovery of the "net revenue requirement impacts" through either a deferral or adjustment in rates.[13] "Net revenue requirement impacts" is commonly understood to mean costs net of benefits. The benefits or savings associated with these projects are zero-fuel cost energy in net power costs and PTC, both of which are captured in the Base EBA. Therefore, an update to the Base EBA would capture the "net revenue requirement impact" required by the MPA statute.

The EBA provides recovery of the difference between the Base EBA and actual EBA each year, so customers will receive the benefits of these projects even without an adjustment to the Base EBA now. However, recovery of benefits would not take place for up to two years after customers receive the benefit due to the lag of deferral and collections in the EBA. The Company's filing proposes to pass those benefits back to customers sooner through a change in the Base EBA. This treatment is in the public interest because it provides a more concurrent matching of costs with benefits of these

[12] Utah Code Ann. § 54-7-13.4(5)(b).
[13] See 54-7-13.4(4)(b)(i) for reference to savings and benefits and (5) for references to "net revenue requirement impacts".

projects.

Q. Do you agree with the DPU's proposal to treat net power cost and PTC benefits on a pro-rated basis to match capital in rates if the Company's application for cost recovery is denied?[14]

A. Yes. The DPU's recommendation would more fairly allow the Company to retain a portion of the benefits to offset the capital costs in rates if the Commission denies the application. However, this approach would require making an adjustment in its annual EBA filings, which would be less straightforward than matching of costs and benefits into rates through this application to implement the net rate decrease now. Alternatively, the MPA statute also authorizes the Commission to defer the costs for future recovery. Ordering a deferral would allow the Commission to leave the Base EBA unchanged; however, it would push out recovery of the deferred capital and increase rates in a future rate case through the addition of amortization of the deferral. Because the Company's application results in a net rate decrease by appropriately matching costs and benefits in rates during the period when the projects are providing service to customers, the Company's proposed approach to update the Base EBA in conjunction with adjustment in base rates is reasonable and in the public interest.

Q. OCS witness Ms. Beck claims that the Company's characterization of its request in this proceeding as a rate decrease is misleading. Do you agree?

A. No. The Company has made it clear in its direct testimony that the decrease is the net impact of revenue requirement costs, net power cost and PTC benefits. The Company has also been transparent that its proposal includes updating the Base EBA, which is

[14] Powell Direct at 261-275.

consistent with the EBA tariff, Electric Service Schedule No. 94.

Q. Has any party made a reasonable argument that the public would be harmed by approving recovery of costs for investments that have been found to be prudent and are currently providing benefits to customers?

A. No. It does not harm customers to pay for projects that are benefiting them. Parties' speculation about the result of allowing recovery here are not based on the circumstances before the Commission in this proceeding. Further, the conflation of the project costs with the test period adopted for the 2020 GRC ignores the clear statutory authority given to the Commission in the MPA statute for alternative cost recovery of major plant additions following a general rate case.

Q. Are there any other issues raised by parties that you would like to address?

A. Yes. I would like to broadly address three additional matters raised by the DPU, specifically, the characterization of the Company's affiliate transactions related to turbines for the projects, concern that the project costs are not final, and the Company will seek to update the costs in rebuttal, and the characterization of errors by the Company in the initial application.

Q. Dr. Zenger makes many statements and poses various questions regarding the Company's affiliate transactions with BHE Wind. How do you respond?

A. Company witness Mr. Van Engelenhoven provides clarification of the affiliate transactions. However, Dr. Zenger mischaracterized the Company's affiliate transaction filings and made incorrect statements. For example, Dr. Zenger stated, "Below I describe how the Company has recently sold back WTG equipment to BHE in an affiliate transaction."[15] This statement is inaccurate, and the Company is unsure of how Dr. Zenger interpreted the affiliate filings and discovery in this manner. The Company filed the required affiliate transaction notices in a timely manner and takes great care in ensuring transparency in these matters.

Q. DPU witnesses Dr. Zenger and Mr. Jones express reservations with the Company's ability to recover costs associated with the wind projects due to the fact that the project costs are forecasts and not final. Dr. Zenger requests the Company clarify if it plans to update the case in rebuttal with an updated forecast. Can you please clarify the Company's intention?

A. Yes. I'll first note that Mr. McDougal will address the statements made by Mr. Jones that final costs are necessary to demonstrate prudency. The Company is not updating any aspect of its request in rebuttal and continues to request recovery of total project costs as outlined in the Company's application and direct testimony.

Q. Dr. Zenger also requests the Company clarify how it will seek recovery for any amounts above [redacted] million for Pryor Mountain and [redacted] million for TB Flats since the final project costs may not be known for several months.

A. As discussed by Mr. Hemstreet and Mr. Van Engelenhoven, it is typical for a project of the size of Pryor Mountain and TB Flats for project costs to take several months to finalize as final close out activities occur. I also think it is worth mentioning that of the forecasted project costs used in this case, only three percent and one percent are unknown for Pryor Mountain and TB Flats, respectively, as discussed in the rebuttal testimony of Company witnesses Mr. Hemstreet and Mr. Van Engelenhoven. However,

[15] Zenger Direct at 458-460

the Company confirms that any cost increases above those presented in this proceeding will be included in a future ratemaking proceeding such as a general rate case and subject to review by parties.

Q. Dr. Zenger characterizes the Company's filing as containing significant errors. Can you please explain the nature of the errors in the filing?

A. Yes. The Company's Application reported in-service nameplate capacity for both projects as of December 31, 2020. The megawatts ("MW") used in the application were taken from the Company's rebuttal filing in the 2020 GRC which were a forecast and did not reflect the updated actual in-service MW that were known at the time of the August 3, 2021 filing. Contrary to Dr Zenger's assertion, this was a genuine oversight that did not affect any aspect of the filing. The Company corrected the mistake through an errata filing on August 26, 2021, as soon as it was discovered. Mr. Van Engelenhoven addresses another typographical error found in his testimony through discovery that also did not impact any aspect of the case. Finally, on lines 397 – 401, Dr. Zenger mentions what she believes is an inconsistency between the Application and Mr. Van Engelenhoven's testimony regarding the number of WTGs. However, as addressed in the rebuttal testimony of Mr. Van Engelenhoven, the Company does not see the error described by Dr. Zenger and believes the numbers provided in the testimony are accurate and were miscalculated by Dr. Zenger.

Q. What is your recommendation for the Commission?

A. The Company requests that the Commission approve the application for full recovery of TB Flats and Pryor Mountain wind projects, effective January 1, 2022.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 21-035-42
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Steven R. McDougal

October 2021

I. INTRODUCTION AND QUALIFICATIONS

Q. Are you the same Steven R. McDougal who filed direct testimony in this proceeding on behalf of PacifiCorp, d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to issues raised by the Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger, Dr. William A. Powell, and Mr. Gary Smith and Utah Association of Energy ("UAE") witness Mr. Kevin C. Higgins. Specifically, my rebuttal testimony recaps the Company's request in this docket and provides a comparison to what has been previously approved by the Public Service Commission of Utah ("Commission") as project costs for the Pryor Mountain and TB Flats wind plants in the general rate case decision in Docket No. 20-035-04 ("2020 GRC"). My rebuttal testimony also highlights how variances in net power costs should not have any effect on the ratemaking treatment outlined in the Company's request in this docket. Lastly, my rebuttal testimony reaffirms the Company's request is prudent and in the interest of Utah customers and should be approved by the Commission.

III. CALCULATION OF REVENUE REQUIREMENT

Q. Please briefly explain the Company's request in this docket.

A. In this docket, the Company is requesting a rate change effective January 1, 2022 associated with the portions of the Pryor Mountain and TB Flats wind projects not included in rates. This rate change is comprised of three major revenue requirement components: the plant revenue requirement which is inclusive of the capital investment, depreciation expense, and accumulated depreciation; the Production Tax Credits ("PTC"); and the Net Power Costs ("NPC") savings. Combined, these revenue requirement components result in a net decrease for Utah customers of approximately $4.2 million.

Q. Is it correct that the $4.2 million net decrease is largely driven by offsets from PTC and NPC?

A. Yes. As provided in Table 1 below, the plant revenue requirement is an increase of approximately $6.7 million, offset by benefits of approximately $6.8 million of PTCs and $4.1 million of net power cost savings. This calculation appropriately matches the remaining capital costs with the full project benefits, an important ratemaking principle the Company considered in this docket.

Table 1

$-Dollars	**TB Flats**	**Pryor Mountain**	**TOTAL**	
Total Plant Revenue Requirement	4,760,098	1,973,728	6,733,826	
PTC Revenue Requirement	(5,039,144)	(1,753,299)	(6,792,442)	
Allocation Factor Impact	(408)	3,493	3,085	
Total Before NPC	**(279,453)**	**223,921**	**(55,532)**	(1)
Net Power Costs			(4,107,441)	(2)
Rev. Requirement			**(4,162,973)**	

(1) Exhibit RMP__(SRM-1), pages 1.1 and 1.2
(2) Exhibit RMP__(SRM-1), page 1.0

Q. Given the recent changes to include PTCs in the Energy Balancing Account ("EBA"), will the Company pass-back PTC and NPC benefits to Utah customers through upcoming EBA filings absent approval of an adjustment to match the benefits with the capital in rates?

A. Yes; but without approval of the Company's Application in this proceeding, customers will receive the benefits of the projects through the EBA but will not pay the full cost of the projects until they are included in Company's next general rate case. As discussed in my direct testimony, the costs and the benefits for these projects were appropriately matched for calendar year 2021 where customers are paying a 13-month average portion of the capital costs and similarly getting a portion of the project benefits that matches the timing of the capital. A mismatch will happen in all years after 2021 if a full year of the benefits are included in the EBA but only a portion of the capital costs are included in customer rates due to the 2020 GRC test period's 13-month average. It is for this exact reason the Company has initiated this proceeding before the Commission and included all components of the revenue requirement (*i.e., capital, depreciation expense, PTC, and NPC*). This will result in customers paying the full project costs to match the full project benefits customers are receiving.

Q. Please explain why customers are only paying a portion of the capital costs based on the 2020 GRC 13-month average rate base.

A. During the pendency of the 2020 GRC, the Company's estimated in-service dates for portions of the Pryor Mountain and TB Flats wind projects were extended beyond the original expected in-service date of 2020 largely due to impacts from

COVID-19. As a result, the Company proposed a two-step rate change that would fully match the costs of the projects with the benefits. This proposal was rejected, and the Commission approved the recovery using a 13-month average rate base. Therefore, the amount included in rates reflects the 13-month average based on the 2020 GRC test period and not the full project costs. Table 2 below illustrates the amount included in customer rates versus the total project cost assumed in the 2020 GRC showing that only 86.0 percent of Pryor Mountains capital cost is included in rates, and only 83.4 percent of TB Flats capital cost is included in rates because of the 2020 GRC test period.

Confidential Table 2

[redacted]

Q. Mr. Higgins states that "the entire amount of plant-in-service for these projects is already included in rate base."[1] Do you agree?

A. No. Because the 13-month average rate base in the 2020 GRC included months when the projects were not yet in service, the entire amount of plant-in-service is not included in rate base. As a result, customers are not paying the full project capital costs. Beginning in 2022, rates will continue to only reflect the 13-month

[1] Direct Testimony of Kevin C. Higgins at Page 8, Ln. 155-156.

average portion of the project capital costs as shown above while customers will receive 100 percent of the benefits in the EBA unless an adjustment is made. This would result in a mismatch under Mr. Higgins' proposal.

Q. If the Commission rejects the Company's proposal, could the cost and benefits of the projects still be matched after 2021?

A. Yes. Dr. Powell recommended that the Commission reject the Company's proposal in this docket and adopt an alternative approach: to pro-rate the benefits customers receive through the EBA to the portion of the capital costs included in customer rates.[2] In other words, using Confidential Table 2 above, the Pryor Mountain PTC and NPC savings would be included in the EBA at 86 percent and TB Flats at 83.4 percent for all years until the rate effective date of the next general rate case.

Q. Does the Company agree with Dr. Powell's alternative recommendation?

A. No. The Company's Application meets the criteria for approval as a major plant addition under Utah Code 54-7-13.4 and should be fully reflected in customer rates. However, Dr. Powell's suggestion is a reasonable alternative and is consistent with a proposal made by the Company in 2020 GRC rebuttal testimony where Ms. Joelle Steward stated: "If the Company's proposed two-step rate change is not accepted, the Company should be able to make adjustments to the EBA and to retain the portion of the benefits associated with the capital not in rates".[3]

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[2] Direct Testimony of Dr. William A. Powell at page 12, Ln. 273-275.

[3] Rebuttal Testimony of Joelle R. Steward, Docket No. 20-035-04 at pages 12-13, Lines 231-233.

Q. In its Application in this proceeding, did the Company update the project costs for Pryor Mountain and TB Flats to reflect more current project cost estimates?

A. Yes. In developing the plant revenue requirement for the Pryor Mountain and TB Flats wind projects, the Company used new project cost estimates. Notably, these estimates used actual project costs through June 2021 to reflect actual in-service amounts and forecasts for the remaining periods.

Q. Is the Company asking the Commission to approve incremental cost increases in the project costs?

A. As shown in Confidential Table 3 below, the Company's more recent project cost estimates are a combined $7.5 million lower, total-Company, than what was approved in the 2020 GRC. The Company's current request in this proceeding for the Pryor Mountain wind project is $[redacted] million which is $[redacted] million less than what was presented in the Company's rebuttal in the 2020 GRC. For the TB Flats wind project, the Company's request in this proceeding is $[redacted] million, which is only $[redacted] million higher than the project costs included in the Company's rebuttal case. The approved project costs from the 2020 GRC are also shown in Confidential Table 2 above.

Confidential Table 3

[redacted]

Q. Is the Company seeking to recover an additional $[redacted] million in project costs for Pryor Mountain as Dr. Zenger claims?[4]

A. No. Dr. Zenger correctly identified the 2020 GRC approved project amount for Pryor Mountain as $[redacted] million on Page 6 and again on Page 15 of her direct testimony. This amount is consistent with the amount included in the workpapers supporting Exhibit RMP__(SRM-1). As of this filing, the Company's current estimate for the total Pryor Mountain project costs is expected to be $[redacted] million. As such, the project costs for Pryor Mountain have decreased by approximately $[redacted] million, total-Company, compared to what was approved in the 2020 GRC.

Q. Are the project costs considered final?

A. No. Project costs are not typically final until approximately nine to 12-months after a project has been commissioned. The cost estimate used in this docket was the best estimate available at the time when preparing the filing. Company witness Mr. Van Engelenhoven addresses this further in his rebuttal testimony.

[4] Direct Testimony of Dr. Joni S. Zenger at Page 13, Ln. 267.

Q. DPU witness Mr. Jones states that "the Division cannot make a recommendation concerning approved cost increases when the amount of those increases is unknown."[5] He also claims that "the Company cannot have met its burden of proof to demonstrate prudency of costs when the costs are not yet known."[6] Would you agree that it is a common ratemaking practice to set customer rates using forecasted project costs?

A. Yes. Forecasted capital project data is commonly used in general rate cases and other ratemaking proceedings when setting customer rates to help reduce regulatory lag on major investment decisions like that of Pryor Mountain and TB Flats. Furthermore, the major plant addition statute allows a company to file up to 150 days before the projected in-service date of a project, which requires the need to use forecast data. The Company consistently uses forecast project data when preparing general rate cases or previous major plant addition filings. This approach was used when setting customer rates in the most recent 2020 GRC and is also being used in this docket. Mr. Jones' claims that the Company cannot meet its burden of proof until project costs are finalized is misguided and has no factual support.

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[5] Direct Testimony of Trevor R. Jones, lines 132-133.
[6] Direct Testimony of Trevor R. Jones, lines 137-139.

NET POWER COSTS

Q. Mr. Smith recommends the "cautious consideration"[7] of changing the EBA base beginning 2022 as requested in this docket. Would you like to address this further?

A. Yes. Mr. Smith recommends "cautious consideration" of changing the EBA base beginning 2022 based on his assertion that a downward adjustment in base rates collected in the EBA would result in a higher collection in future periods. His analysis compared the period January through June 2021 in which the Company's actual NPC and PTCs were different from the amount forecasted in the 2020 GRC. Although I have no reason to doubt his comparison of these very specific six months of data, I do not believe this short period of data is reflective of conditions expected to occur in a full calendar year nor a future calendar year and certainly not over the life of the projects. The differences in this short six-month period are driven not only by changing wind conditions but also by market conditions, economic factors, and other generation availability. Ensuring the Company is appropriately matching the costs and benefits for additional known availability of the Pryor Mountain and TB Flats wind projects is critical and should be considered by the Commission in this docket. Electric Service Schedule No. 94 clearly contemplates major plant addition cases as an eligible proceeding to update the EBA Base to align the cost recovery with the benefits. The Company believes it is in the best interest of customers to update the EBA base to reflect benefits in customers rates *sooner* and does not believe the DPU has offered any persuasive

[7] Direct Testimony of Gary Smith at Page 9, Ln 118

reason why customers should be required to wait to receive the benefits.

Q. Mr. Smith points to the actual net power costs for the first six months of 2021 compared to the forecast in the general rate case to argue that updating the EBA Base would not be in the public interest. Can you please respond?

A. These variances are total-Company amounts for the Company's entire system and not solely isolated to Pryor Mountain and TB Flats. Variances in NPC and PTCs reflect a variety of conditions and are not a reason to ignore matching the costs and benefits of these projects. As I discussed earlier in my testimony, the EBA now includes a full pass through of both PTC and NPC. Any variation between the EBA base proposed in this docket and actual NPC and PTC will be trued up at 100 percent.

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 21-035-42
Witness: Robert Van Engelenhoven

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Robert Van Engelenhoven

October 2021

Q. Are you the same Robert Van Engelenhoven that filed direct testimony on behalf of PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company") in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony of Division of Public Utilities ("DPU") witness Dr. Joni S. Zenger. Specifically, I address misunderstandings in her testimony regarding the Company's Application in this matter, concerns regarding the fact that final costs for the project are not yet known, and questions raised regarding affiliate transactions with Berkshire Hathaway Energy Wind, LLC ("BHE Wind").

Q. Do you have any corrections to your direct testimony in this matter that you would like to make at this time?

A. Yes. In my direct testimony, at lines 75 - 76, I stated that the total project cost for the Pryor Mountain wind project in this filing was $[redacted] and that this cost was slightly higher than the projected cost of $[redacted], which was the amount approved by the Public Service Commission (the "Commission") in the Company's 2020 general rate case ("2020 GRC").[1] This sentence should read: the total project cost for the Pryor Mountain wind project in this filing was $[redacted] and that this cost was slightly [redacted] than the projected cost of $[redacted], which was the amount approved by the Commission in the 2020 GRC.

[1] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 20-035-04.

Q. Does this correction change any other aspects of the Company's filing, including the recovery requested?

A. No. This did not affect any other aspect of the Company's request.

Q. The direct testimony of DPU witness Dr. Joni S. Zenger raises questions about what the Company is now asking the Commission to approve regarding the Pryor Mountain wind project.[2] How do you respond to the questions raised by Dr. Zenger?

A. The Company reiterates that with this filing, it is not seeking approval for costs beyond the $[redacted] approved in the 2020 GRC. The Company currently projects total costs for the Pryor Mountain wind project to be approximately $[redacted], which is nearly three percent lower than the projected costs already approved by the Commission.

Q. Dr. Zenger also states that the Company's Application and your direct testimony are inconsistent regarding the total number of wind turbine generators ("WTGs") that are included in the Pryor Mountain wind project.[3] How do you respond to this assertion?

A. The genesis of the confusion surrounding this issue is unclear to me. Dr. Zenger cites my direct testimony at page 2, lines 24 - 25 as stating the project consists of 110 WTGs. However, my direct testimony states that the project consists of 114 WTGs, which is the same as the Company's Application in this case. As I stated in my direct testimony

[2] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 13, lines 272 – 73 ("it is unclear what the Company is now requesting the Commission to approve with respect to Pryor Mountain) and p. 14, lines 307 – 08 ("The Division is not aware of what cost elements, if any, the Company is request approval of.").
[3] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 19, lines 397 – 401 ("The Application reports a total of 114 different WTGs, versus the 110 reported by Mr. Van Engelenhoven.").

at page 2, lines 24 - 25, the Pryor Mountain wind project consists of "57 Vestas Model V110-2.0 MW [safe harbor], 16 Vestas Model V110-2.2 MW [safe harbor], four General Electric Model 116-2.3 MW [safe harbor], and 37 Vestas model V110-2.2 MW follow-on wind turbine generators." (Emphasis added). The total of the various models of WTGs—57, 16, four, and 37—is 114.

Q. Why are the total costs for the Pryor Mountain wind project still projected and why is the Company unable to finalize those costs at this time?

A. At this time, the Company has booked approximately $[redacted] of the total forecasted projects costs of $[redacted]. However, as noted previously, Pryor Mountain was built during the COVID-19 pandemic, which resulted in force majeure and excusable event notices from the Company's contractors. Negotiations with both the turbine supply contractor and the balance of plant contractor are ongoing and anticipated to be complete by the end of 2021. Total project costs will not be finalized until that time.

In addition, as with any of the Company's projects of the scope of Pryor Mountain, completion activities and the final determination of the costs associated with those activities do not conclude immediately when the turbines are placed into service. Ongoing work, such as site reclamation, county and site road repairs, site restoration, revegetation, project documentation, completion of punch list items, and permit close-out activities, continue after commercial operation is achieved. These activities may also constitute final project components tied to contractual milestones for which liquidated damages may be owed as a result of potential delays. Final project costs are unknown until all these items are completed, typically within nine to 12 months after a project has achieved commissioning.

[redacted]

[4] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 21, lines 444-447.

[redacted]

[redacted]

[5] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 21, lines 450-451.
[6] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 21, lines 456-457.

[redacted]

[redacted]

[redacted]

[7] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 23, lines 489-494.
[8] Confidential Direct Testimony of Dr. Joni S. Zenger, October 6, 2021, p. 22, lines 472-476.

[redacted]

Q. Does this conclude your rebuttal testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 21-035-42
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Timothy J. Hemstreet

October 2021

Q. Are you the same Timothy J. Hemstreet who previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

I. PURPOSE OF TESTIMONY

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

A. The purpose of my rebuttal testimony is to address issues raised by the Division of Public Utilities ("DPU") witness Mr. Trevor R. Jones regarding the TB Flats wind project.

II. TB FLATS WIND PROJECT

Q. DPU witness Mr. Jones claims that he is unable to make a recommendation regarding TB Flats wind project in this proceeding because the project costs are not yet final. Why are the total costs for the project still projected and why is the Company unable to finalize those costs at this time?

A. At this time, the Company has incurred approximately $[redacted], of the total forecasted projects costs for TB Flats of $[redacted], leaving just $[redacted] in remaining forecast costs. As noted by Mr. Jones, TB Flats was built during the COVID-19 pandemic, which resulted in force majeure and excusable event notices from the Company's contractors. Negotiations with both the turbine supply contractor and the balance of plant contractor to resolve these claims are ongoing and anticipated to be complete by the end of 2021. Consistent with utility accounting procedures, total project costs cannot be finalized until that time. However, as I noted, the vast majority—[redacted] percent—of these costs are known.

In addition, as with any of the Company's large projects with the scope of the TB Flats wind project, completion activities and the final determination of the costs associated with those activities do not conclude immediately when the turbines are placed into service. Ongoing work, such as site reclamation, county and site road repairs, site restoration, revegetation, project documentation, completion of punch list items, and permit close-out activities, continue after commercial operation is achieved. These activities may also constitute final project scope items tied to contractual payment milestones. Final project costs are unknown until all these items are completed, typically within nine to 12 months after a project has achieved commissioning.

Q. Mr. Jones also states that the Company is only requesting approximately $[redacted] in project costs above what was previously approved in the last general rate case, Docket No. 20-035-04. Is this correct?

A. Yes. This is correct.

Q. Did the Company provide support for the relatively small cost increase through discovery?

A. Yes. These additional costs were due to the COVID-19 pandemic, which fully used project contingency amounts set aside to deal with unforeseen project issues, and the Company provided supporting documentation through discovery for these increases. This support included force majeure claims, change orders, and contractor invoices.

Q. Mr. Jones includes an excerpt of one of the contractor invoices and points to an area of the invoice where a [redacted] markup was added. Could you please explain what this markup includes and why is it prudent?

A. The Company's negotiated balance of plant contract includes a provision for approving change order costs that are based on actual contractor costs plus [redacted] markup. This provision is used to price work scopes for which unit pricing established under the contract is not applicable. As site conditions and/or work requirements change over the course of a project, it can be difficult to estimate the cost to address an established project need that is the subject of a change order request. The [redacted] markup allows for work to proceed under this uncertainty and ensures that the Company does not overpay for a scope change order that would otherwise be priced at firm, fixed pricing that covered all "worst case" assumptions about the level of effort necessary to complete the additional work. The [redacted] markup on the contractor's direct costs provides an allowance for the contractor's administrative and general costs, insurance, bonding, financing, and margin.

IV. CONCLUSION

Q. Please summarize your testimony and recommendations.

A. The Company has prudently managed the construction of the TB Flats project and project costs are reasonable given the extraordinary conditions of the pandemic, which has constituted a force majeure event under the company's executed turbine supply and balance of plant construction contracts and thereby resulted in costs for construction delays that were outside the control of the company. While project costs are not yet finalized given the ongoing nature of final project completion activities, [redacted] percent of the project costs are now final and the remaining forecasted costs reflect activities that will be completed in the near future. Given the Company has prudently managed construction of the TB Flats project, I recommend that the Commission allow the Company to recover its costs associated with the TB Flats wind project.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 21-035-42
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Robert M. Meredith

October 2021

Q. Are you the same Robert M. Meredith who submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or "the Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony in this proceeding is to respond to the direct testimony of Mr. Justin Bieber for the Utah Association of Energy Users ("UAE").

Q. Please summarize Mr. Bieber's rate design concerns for this proceeding.

A. Mr. Bieber contends that the Company's rate design logic for setting Schedule 32 prices in this proceeding is not the same as what the Commission ordered in the Company's 2020 General Rate Case in Docket No. 20-035-04 ("2020 Rate Case"). Specifically, he recommends that the Daily Power Charges in combination with the Delivery Facility Charges should recover the same level as the cost of Facilities and Power Charges that are applicable to full requirements customers and that the rate spread logic should consider applying the Schedule 9 price change to all of Schedule 32's revenue inclusive of renewable procurement costs. He then claims that "the method proposed by RMP does not result in any actual decrease to Schedule 32 base rates or base revenue collected from Schedule 32 customers."[1]

Q. Please describe how the Company applied the 2021 Major Plant Additions ("MPA") price change to Schedule 32 customers.

A. The Company applied the same percentage price decrease for Schedule 9 to Schedule 32's revenue, excluding renewable procurement costs. Because of rounding,

[1] Direct Testimony of Justin Bieber ("Bieber Direct"), lines 237-239.

this resulted in no change to the prices actually posted on Schedule 32. Charges to Schedule 32 for supplemental energy and power decreased, since they rely on Schedule 9.

Q. Why is it reasonable to only consider revenue that excludes renewable procurement costs for the purposes of this proceeding?

A. As opposed to a general rate case where all aspects of utility service are examined, this 2021 MPA proceeding is limited to recovery of the revenue requirement associated with two specific wind projects. Therefore, it is reasonable for the price change from these two projects to be limited to the proportion of Schedule 32's revenue that is related to service supplied from Company resources.

Q. The inclusion of Schedule 32's renewable procurement costs when determining rate spread in the 2020 Rate Case was a disputed issue during reconsideration.[2] Why did the Company oppose this particular aspect of UAE and University of Utah's petition for reconsideration?

A. The Company's primary concern with UAE and the University of Utah's request was that it was untimely. If they felt there was a problem with the Company's proposed rate spread for Schedule 32 in the 2020 Rate Case, that concern should have been raised in testimony by one of their witnesses instead of in its petition for reconsideration in the 2020 Rate Case.

[2] *See Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, D*ocket No. 20-035-04, Order on Petitions for Review, Reconsideration, or Rehearing (February 26, 2021) ("Rehearing Order") at 9.

Q. Was the rate spread logic of considering the renewable procurement costs a part of revenue the main driver for Schedule 32's price increase in the 2020 Rate Case?

A. No. Most of the price increase for Schedule 32 in the 2020 Rate Case was related to the greater increase to demand charges for Schedule 9 and the rate design logic that Schedule 32 demand rates were designed to recover the same level of cost as the combination of Facilities and Power demand charges applicable to full requirements rate schedules.[3] Adjusting the pricing for Schedule 32 such that its total revenue had the same revenue increase as Schedule 9 only accounted for about $34 thousand[4] out of the roughly $350 thousand[5] increase in the 2020 Rate Case.

Q. In the Company's next general rate case, how do you think rate spread/rate design for Schedule 32 should be handled?

A. In future general rate cases, when all costs are under consideration, the Company will have a full 12 months of data from Schedule 32 customer(s) from which it may include them in its cost of service ("COS") study. At that time, the Company's rate spread proposals could be based upon the results in a COS study specifically for a Schedule 32 class instead of relying upon another class, such as Schedule 9, as a proxy to make rate spread proposals.

[3] *See* RMP Response at 16.
[4] *See* Rocky Mountain Power's Response in Opposition to Petitions for Reconsideration, Review, or Rehearing in Docket No. 20-035-04 (February 16, 2021) ("RMP Response") at 15.
[5] *See* Rehearing Order at 14.

Q. Do you agree with Mr. Bieber that "(i)t would not be consistent or reasonable to include the renewable procurement contract costs in the 2020 Rate Case to determine the target revenue *increase*, but then to exclude those same renewable procurement contract costs in this proceeding from the determination of the target revenue *decrease*"?[6]

A. I do not agree with Mr. Bieber that the Company's approach to rate spread is inconsistent or unreasonable. In general rate cases, all costs of utility service and charging components are under review. In the 2020 Rate Case, the preponderance of Schedule 32's price increase was related to higher increases to demand-related components for Schedule 9. Applying the same increase to Schedule 32 and Schedule 9, inclusive of renewable procurement costs, was of secondary importance. The 2021 MPA is a separate and limited docket where past Commission decisions from the 2020 Rate Case should not be relitigated. Only recovery of the revenue requirement related to the two wind projects is under consideration in this proceeding, and the Company is requesting a relatively small decrease of 0.2 percent to be applied to base energy and power charges. Given the purpose of the 2021 MPA proceeding, the Company believes its rate spread logic is fair. If the 2021 MPA had been a rate increase, I would have proposed the same logic for Schedule 32.

Q. What is your recommendation for the Commission?

A. I recommend that the Commission approve the Company's proposed prices for the 2021 MPA.

[6] Bieber Direct, Lines 271-274.

Q. Does this conclude your rebuttal testimony?

A. Yes.