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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

Application of Rocky Mountain Power for an Accounting Order to Defer Costs Related to Repowered Wind Plants or for Alternative Relief	**Docket No. 19-035-45**

REDACTED PREFILED DIRECT TESTIMONY AND EXHIBITS OF KEVIN C. HIGGINS

The Utah Association of Energy Users ("UAE") hereby submits this Redacted Prefiled Direct Testimony of Kevin C. Higgins in this docket.

DATED this 4th day of March 2020.

HATCH, JAMES & DODGE, P.C.

Phillip J Russell

Phillip J. Russell
Attorneys for the Utah Association of Energy Users

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 4th day of March 2020 on the following:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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REDACTED Direct Testimony of Kevin C. Higgins

On Behalf of the

Utah Association of Energy Users

March 4, 2020

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Utah Association of Energy Users ("UAE").

Q. Please summarize your qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before the Utah Public Service Commission ("Commission")?

A. Yes. Since 1984, I have testified in forty-one dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in approximately 210 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission and prepared expert reports in state and federal court proceedings involving utility matters.

Q. What is the purpose of your direct testimony?

A. My testimony addresses the request by Rocky Mountain Power ("RMP") for an accounting order pertaining to twelve wind repowering projects. RMP requests that certain costs and benefits associated with these projects be deferred starting from the time these projects are placed into service and continuing until the rate effective date of the next general rate case. Alternatively, if the Commission determines that the costs, net of the Production Tax Credit ("PTC") and low-cost fuel benefits associated with these facilities, are not appropriate for deferred accounting, RMP requests that the Commission issue an order allowing removal of the low-cost fuel benefits of these projects from the Energy Balancing Account ("EBA") until the rate effective date of the Company's next general rate case.[1]

Q. What is your recommendation to the Commission regarding RMP's request?

A. I recommend that the Company's request – and its alternative request – be denied.

II. RMP REQUEST FOR DEFERRED ACCOUNTING

Q. Briefly summarize RMP's request in this case.

A. In Docket No. 17-035-39, the Commission approved RMP's voluntary request for a resource decision pertaining to eleven wind repowering projects ("Repowering Projects") and declined approval for a twelfth repowering project, Leaning Juniper.[2] The Commission also declined RMP's request for special ratemaking treatment for these projects, termed the Resource Tracking Mechanism ("RTM"). RMP's request for deferred accounting in this case pertains to these twelve repowering projects.[3]

RMP seeks to defer certain costs and benefits on a monthly basis starting when the Repowering Projects and Leaning Juniper are placed into service until rates from the

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[1] Direct Testimony of Steven R. McDougal, lines 26-44. I am referring to the cost of energy from these projects as "low cost" rather than "zero cost" (as RMP describes them) since they are expected to incur integration costs.

[2] I reference here the terminology used by RMP in its filing (eleven "Repowering Projects" and "Leaning Juniper"). For ease of exposition, I will occasionally refer to these projects together as the "twelve repowering projects," without capitalization.

[3] RMP's Application in this docket makes reference to and provides data regarding the repowering of an additional project, titled Foote Creek I. RMP's Application does not, however, request deferred accounting for the Foote Creek I project.

next general rate case reflect the full costs and benefits. The specific items RMP proposes to defer are:

- Pre-tax return on investment;
- Depreciation expense;
- Operation and maintenance expense;
- Property taxes;
- Wind taxes, if assessed;
- Incremental net power cost ("NPC") benefits; and
- PTC benefits.

Q. What is the Company's justification for the requested deferral?

A. All twelve projects are expected to be in service prior to the rate effective date of the next general rate case. Absent a deferred accounting order, cost recovery for these projects will not begin until the rate effective date of the rate case. In the meantime, when these projects come on-line, they will produce low-cost energy that will reduce NPC, all things being equal, the benefit of which will flow through the EBA to customers. Thus, RMP asserts that there will be a period of time in which the twelve repowering projects will be producing benefits realized by customers while the projects' costs are not contemporaneously recovered in rates. RMP asserts that deferred accounting is appropriate to address this timing issue.[4]

[4] Direct Testimony of Steven R. McDougal, lines 153-159.

Q. What is RMP's alternative proposal?

A. Alternatively, if the Commission determines that the costs, net of the PTC and low-cost fuel benefits associated with these facilities, are not appropriate for deferred accounting, RMP requests authority to implement an exception to the EBA to remove the incremental benefits of the Repowered Wind Plants and Leaning Juniper until the rate effective date of the Company's next general rate case.[5]

III. RESPONSE TO RMP'S REQUEST FOR DEFERRED ACCOUNTING

Q. What is your response to RMP's request for deferred accounting?

A. I recommend that the Company's request – and its alternative request – be denied.

Q. Please explain the basis for your recommendation.

A. There are several reasons for my recommendation. First, as a threshold matter, I do not believe the Repowered Projects and Leaning Juniper meet the general criteria for deferred accounting in Utah. Indeed, RMP admits in its own Application that its Application "does not meet the traditional standard" for deferred accounting that this Commission has previously required it to meet.[6]

Second, as a matter of regulatory policy, the temporary timing concerns raised by RMP in its filing do not justify the imposition of single-issue ratemaking treatment in lieu

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[5] *Id*., lines 163-169.

[6] RMP Application at 5, ¶ 9 (citing the standard set forth in *MCI Telecommunications Corp. v. PSC*, 840 P.2d 765 (Utah 1992)). This Commission has recently rejected RMP's requests to obtain a deferred accounting order under other circumstances when the request does not meet the *MCI* standard, concluding that "where RMP seeks deferred accounting to facilitate potential recovery of a specific category of prior year pension expenses in a future general rate case, the principles of both retroactive ratemaking and single-issue ratemaking require us to apply the legal standard in *MCI*." *Application of Rocky Mountain Power for an Accounting Order for Settlement Charges Related to its Pension Plans*, Docket No. 18-035-48, Order at 5 (Utah P.S.C. May 22, 2019).

of standard ratemaking practices, particularly given the circumstances and facts of this case. Thus, to the extent that the Commission considers RMP's request, despite the fact that it fails to meet the traditional and required deferred accounting standards, the request should still be denied on its merit, as explained in my testimony. This is particularly true since the temporary timing concerns arise fully as a result of RMP's own decision making and derive in part from the prior adoption of *another* regulatory mechanism that generally benefits RMP, the EBA.

Third, RMP's calculations of the net benefits from the Repowered Projects and Leaning Juniper prior to the rate effective period fail to consider the cost to customers during that same period from the lost output from those facilities between the time of their premature retirement and the restart of the facilities after repowering, and thus, is an example of the adverse selection that can occur with a single-issue ratemaking request.

Q. What is your understanding of the criteria for deferred accounting in Utah?

A. It is my understanding that in Utah, the rule against retroactive ratemaking generally precludes the ratemaking process from being influenced by actual costs or revenues that deviate from rate case estimates; consequently, deferred accounting outside a general rate case (other than fuel adjustor mechanisms) is generally limited to situations in which changes in cost or revenues are unforeseen and extraordinary.[7]

[7] See *Utah Department of Business Regulation v. Utah Public Service Commission*, 720 P.2d 420 (Utah 1986); *MCI Telecommunications Corporation v. Utah Public Service Commission*, 840 P.2d 765, 771-772 (Utah 1992); Report and Order, Utah PSC Docket Nos. 06-035-163, 07-035-04, 07-035-14, at 15 (January 3, 2008); Report and Order, Utah PSC Docket No. 18-035-48.

Q. Do you believe that the costs RMP is requesting to defer in this case fit these general criteria?

A. No. The costs associated with the twelve repowering projects for which RMP seeks deferred accounting are certainly not unforeseen. Rather, they were the subject of an extensive inquiry in Docket No. 17-035-39. Moreover, the incurrence of these costs results from projects that were proposed and planned by RMP. The Company sought approval for these projects and proceeded to undertake them with the full knowledge that it would control the filing date for its next rate case and that the twelve repowering projects would most likely be in service prior to the rate effective period of that next case. Moreover, RMP's own Application readily concedes that the twelve repowering projects do not meet the traditional criteria for deferred accounting in Utah.[8]

Q. Putting aside the question of whether RMP's proposal meets the traditional criteria for deferred accounting in Utah, what is your response to the Company's proposal from a regulatory policy standpoint?

A. Purely from a ratemaking policy perspective, I recommend that RMP's request be denied. Most requests for deferred accounting are attempts to engage in single-issue ratemaking. RMP's request for deferral in this proceeding is no exception.

Q. What is single-issue ratemaking?

A. Single-issue ratemaking occurs when utility rates are adjusted or deferred in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores

[8] *See* RMP Application, paragraph 9. "[T]his Application does not meet the traditional standard [for deferred accounting] in *MCI*…"

the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When utility regulatory commissions determine the appropriateness of a cost that a utility seeks to recover from its customers, the standard practice is to review and consider *all* relevant factors as part of a general rate case, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates or defer costs in the area singled out for attention without recognizing counterbalancing savings in another area. Because single-issue ratemaking focuses on specific costs in isolation, utility regulatory commissions should view proposals for deferral with great caution.

Q. How does this need for caution apply to RMP's request for deferred accounting in this case?

A. As the Commission well knows, utility ratemaking is not an exercise in expense reimbursement. The opportunity for utility cost recovery is established in the *rates* approved by the Commission. We know that in reality costs and revenues are almost certain to differ from what was projected at the time rates were set. The simple fact that a utility incurs a cost that differs from what was anticipated when rates were set does not create an obligation on the part of the regulator to establish a mechanism for reimbursement. While there may be limited situations in which singling out certain items for deferral is appropriate, as a general matter, costs incurred as a result of actions initiated by the utility and not beyond its control do not create a good case for deferred accounting treatment.

Q. Mr. McDougal states that he believes the upgrades made for the twelve repowering projects may also qualify for deferred accounting under Utah Code Ann. § 54-17-605, titled "Recovery of costs for renewable energy activities." Do you have any comments in response?

A. Yes. This section of the Utah Code states that the Commission may allow an electric utility to defer certain renewable energy costs *to the extent deferral is consistent with other applicable law.* [Emphasis added.] As I am not an attorney, I will not attempt to interpret this qualifying language. However, this section of the code appears to leave the determination of whether a deferral is appropriate to the Commission. To the extent that the Commission considers RMP's deferral request, I recommend that the Company's request be denied as a matter of ratemaking policy. As I stated above, the temporary timing concerns raised by RMP in its filing do not justify the imposition of single-issue ratemaking treatment in lieu of standard ratemaking practices, particularly given the circumstances and facts of this case.

Q. Please elaborate on your last statement.

A. In its request for preapproval for the twelve repowering projects, RMP proposed a special cost recovery mechanism, the RTM, which was denied by the Commission. The Company pursued the repowering projects nonetheless, including the Leaning Juniper project, which was expressly denied preapproval by the Commission due to the inferior economics of that project and the materially higher risks it poses for ratepayers, particularly during the 20-year period following repowering.[9] Since RMP controls the

[9] Docket No. 17-035-39, Report and Order issued May 25, 2018 at 19-20.

timing of its rate case filings and will not file a case in time to allow traditional cost recovery for the twelve projects to occur prior to January 1, 2021, the timing concerns expressed by the Company – and for which it seeks relief from the Commission – are in large part the product of its own planning.

Notably, the source of benefits to customers prior to the costs of the projects coming into rates (under traditional ratemaking) is the EBA, which was established at the Company's request and already provides substantial benefits to RMP, but which acts in this instance to pass benefits through to customers prior to the rate effective date of the next general rate case. In essence, RMP seeks relief in this case from the side effects of the very regulatory mechanism it championed. This is not a compelling argument.

Broadly speaking, the EBA conveys significant benefits to RMP because it allows the Company to recover 100 percent of the divergence in prudent actual NPC relative to the NPC embedded in rates, thereby transferring 100% of the risk of such divergences to customers. In this instance, however, the EBA provides a timing benefit to customers. The Commission should not impose a new single-issue ratemaking device to neutralize the effects of this temporary benefit to customers, which is a consequence, in the first place, of layering into rates a special purpose adjustment mechanism like the EBA. Moreover, as initially approved by the Commission, the EBA incorporated a 70/30 sharing mechanism that, if it had been left intact, would have passed through to the Company a portion of the energy-cost-saving benefits from the wind plants prior to the rate effective date. The elimination of the sharing mechanism was the result of strident and persistent efforts by the Company over the opposition of customer advocates.

Having achieved its goal of eliminating the EBA sharing mechanism, it is unreasonable for the Company to expect the Commission now to "cure" one of the side effects of that elimination.

Q. Please explain your concerns regarding RMP's failure to consider the cost to customers from the lost output between the time the original facilities were retired and the restart of the facilities after repowering.

A. RMP proposes to start the deferral for each facility at the date of repowering, not the date of shut down of each original facility to accommodate the repowering. The installation period for each repowering project was projected by RMP to last between 11 and 31 weeks,[10] during which time a portion of the benefits from the low-cost energy output from the original facilities, each of which was originally slated to operate until at least 2036, is lost to customers, resulting in higher NPC, all things being equal. None of the *costs* to *customers* of the foregone benefits during the installation period is included in RMP's net deferred cost calculations. That is, RMP makes no attempt to net the NPC benefits foregone by customers during the installation period against the deferred costs that RMP seeks to recover from them.[11] This is an example of the adverse selection that can occur with a single-issue ratemaking request.

[10] Docket No. 17-035-39, Direct Testimony of Timothy J. Hemstreet, Exhibit RMP No.__(TJH-5).
[11] *See* RMP Response to UAE Data Requests 3.1 and 5.1, included in UAE Exhibit 1.1. RMP indicates that the average duration of a turbine outage to complete repowering equipment removal and installation is approximately [redacted] (*See* RMP Confidential Response to UAE Data Request 6.6, which is provided in UAE Confidential Exhibit 1.2.) By way of illustration, using this average duration and treating the average output of the affected plants over the period 2013-18 as a baseline, the cost to Utah customers from this lost output applied to the fleet of plants being repowered is around [redacted] if the foregone output is valued at $30/MWh.

Q. Do you have any other concerns regarding RMP's request?

A. Yes. It is important to recognize that implementation of RMP's request would be complicated. There are many moving parts to track. Moreover, the values for at least one key item, the benefit from incremental generation, would have to be imputed by assigning a market price to the generation output deemed to be incremental as a result of the repowering investment. Even the EBA, while straightforward in concept, is complicated to implement. The deferral proposed by RMP would be even more so. While sometimes complexity is necessary to ensure just and reasonable rates, I do not believe the circumstances giving rise to RMP's deferral request warrant the additional administrative burden that would accompany its implementation.

Q. Has RMP estimated the cost to Utah customers of the requested deferral?

A. The expected cost of the deferral is not expressly presented in RMP's filing. Rather, Mr. McDougal presents an example calculation of the monthly deferral for the Seven Mile Hill I and II repowering projects.[12] He also presents a confidential table that shows the projected incremental energy production for each of the twelve repowering projects, from which the deferral would be calculated.[13]

However, the Company's estimate of the deferral amount can be inferred from discovery responses. In RMP's 1st Revised Response to OCS Data Request 2.20, RMP indicates that its estimate of the 2020 calendar year deferral is a credit of ($6.6) million.[14] The credit was calculated by taking the $9.1 million cost estimated in Exhibit

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[12] Exhibit RMP__(SRM-2), p. 1.
[13] Confidential Exhibit RMP__(SRM-2), p. 2.
[14] This response is included in UAE Exhibit 1.1.

RMP__(JRS-2SD) filed with the Supplemental Direct Testimony of Joelle R. Steward in Docket No. 17-035-39 and including a credit adjustment of ($15.7) million for depreciation expense. This depreciation expense credit adjustment recognizes the depreciation expense that Utah customers pay in current rates for the twelve repowered facilities prior to repowering; that is, it represents the depreciation expense being recovered in current rates on the original investment for the twelve wind plants at issue.

The 2020 deferral credit would be partially offset by a 2019 deferred cost of nearly $1.0 million as shown in RMP Response to OCS Data Request 2.18.[15] The combined 2019 and 2020 deferrals give rise to an estimated deferral credit of ($5.6) million on a Utah jurisdictional basis. This information is summarized in Table KCH-1 below.

Table KCH-1
RMP Projected Utah Deferral[16]

	Deferral Excluding Depreciation Credit	Depreciation Credit	Deferral Including Depreciation Credit
2019	$3,141,749	($2,170,507)	$971,242
2020	$9,131,393	($15,728,645)	($6,597,252)
Total	$12,273,142	($17,899,152)	($5,626,011)

Q. If the deferral results in a credit, doesn't RMP's deferral request produce a net benefit for customers?

A. No. The projected deferral results in a "credit" only because it includes the depreciation expense credit adjustment. In my view, the depreciation expense that Utah customers

[15] See RMP 1st Supplemental Response to OCS Data Request 2.18, Attachment OCS 2.18 1st Supp, included in UAE Exhibit 1.1.
[16] Data Source: RMP 1st Supplemental Response to OCS Data Request 2.18, Attachment OCS 2.18 1st Supp, included in UAE Exhibit 1.1.

currently pay in rates should properly be credited to Utah customers *anyway* (as a cumulative reduction to rate base) – irrespective of whether RMP's requested deferral is granted. If we set aside the inclusion of the depreciation expense credit adjustment, the deferral produces an estimated deferred cost to customers of $3.1 million in 2019 and $9.1 million in 2020. That is, if we accept that the depreciation expense should properly be credited to Utah customers in the first place, then the incremental impact of the requested deferral is to impose a net cost on Utah customers in the projected amount of $12.3 million as shown in Table KCH-1 above.

Moreover, the deferral credit calculation includes $(5.5) million in projected NPC benefits from incremental wind generation produced by the repowered projects that would otherwise flow to customers through the EBA prior to the rate effective date. In order to include the incremental NPC benefits from the repowered projects as a credit in RMP's requested deferral, RMP would first *remove* these benefits from the EBA, where they would otherwise accrue.[17] In my view, shifting the NPC benefits from the EBA to the deferral is a needless exercise. The only purpose it seems to serve is to create the appearance of a smaller deferral cost (or larger deferral credit) than would otherwise obtain. As shown in Table KCH-2 below, if the depreciation expense credit (which customers *should* receive anyway) and incremental NPC savings (which customers *would* receive anyway) are both removed from the deferral, the incremental benefit of the deferral to RMP is the ultimate recovery of an additional $17.8 million in costs.

[17] See RMP Response to OCS Data Request 2.16, which is included in UAE Exhibit 1.1.

Table KCH-2
RMP Projected Utah Deferral Components[18]

	Deferral Excluding NPC Savings & Depreciation Credit	Incremental NPC Savings	Deferral Excluding Depreciation Credit	Depreciation Credit	Deferral Including NPC Savings & Depreciation Credit
2019	$4,202,244	($1,060,495)	$3,141,749	($2,170,507)	$971,242
2020	$13,584,282	($4,452,890)	$9,131,393	($15,728,645)	($6,597,252)
Total	$17,786,526	($5,513,384)	$12,273,142	($17,899,152)	($5,626,011)

Q. If the Company's request for deferred accounting is denied, how can the depreciation expense in current rates associated with the original investment in the affected wind plants properly be credited to Utah customers?

A. The depreciation expense in current rates associated with the original investment in the repowered wind plants can properly be credited to Utah customers by crediting the expense toward the "implicit balance" of the retired assets.[19] This issue will be addressed by UAE in the current depreciation case, Docket No. 18-035-36. The proper crediting of current depreciation expense can be accomplished either by (1) converting the undepreciated balances of the original wind assets on their retirement dates into a regulatory asset, which would continue to be amortized until January 1, 2021, the presumed rate effective date of the next general rate case, or (2) adjusting the *depreciation reserve* by the cumulative amount of the depreciation expense in rates associated with the original assets, starting from the dates of their retirements and running through January 1, 2021.

[18] Data Source: RMP's 1st Supplemental Response to OCS Data Request 2.18, Attachment OCS 2.18 1st Supp, included in UAE Exhibit 1.1.
[19] I refer here to the "*implicit* balance" of the retired assets because the accounting treatment proposed by RMP for the retired assets actually eliminates the retired assets balance *per se* on the books, even though the remaining costs of the retired assets would still be recovered from customers in depreciation expense.

Q. Why would either of these actions be necessary? Wouldn't the depreciation expense in current rates associated with the original assets be applied to the retired asset balance through January 1, 2021 under the status quo?

A. No. While that may be a plausible and intuitive expectation, that is apparently not the case. It is my understanding, based on my involvement in Docket No. 18-035-36, that RMP's accounting treatment of the undepreciated balances of the retired assets results in those balances being effectively "frozen" at the balances that existed on the date of each asset's retirement. These balances would remain effectively frozen until the rate effective date of the next rate case, rather than continuing to decline after their respective retirement dates. This accounting treatment is being implemented through a simultaneous removal of the asset from plant-in-service while debiting the accumulated depreciation reserve. This approach was proposed by RMP witness Jeffrey Larsen in his direct testimony in the repowering case, Docket No. 17-035-39,[20] and incorporated into the depreciation case.

The accounting treatment being used by RMP does not change the Company's net plant balance, but shifts the accumulated depreciation reserve from a negative to a positive balance. That is, these bookkeeping entries cause the credit in rate base provided by the accumulated depreciation reserve to be *reduced* by the original cost of the retired plant in service (as the retired plant is removed from plant-in-service). In this manner, RMP would recover the original cost of the retired plant, not by amortizing the original

[20] Docket No. 17-035-39, Direct Testimony of Jeffrey K. Larsen, lines 354-363.

plant-in-service, but by effectively depreciating the new debit entry in the accumulated depreciation reserve.

Q. What is your concern with this approach?

A. My concern with this approach is that it effectively freezes the undepreciated balances of the retired plant at the balances that existed on the date of retirement until the rate effective date of the next rate case – even though customers continue to pay depreciation expense on these plants in current rates. Instead, RMP proposes to apply the current depreciation expense paid by customers in rates attributable to the *retired* plant as a credit against the depreciation expense of the *new* repowered plant (as proposed in this docket). As such, RMP's approach provides the Company part of what it is seeking in its deferral request *de facto* – namely, recovery of new plant investment prior to the rate effective date. While the issues surrounding depreciation of the retired wind plant will be addressed by UAE in the depreciation docket, I am identifying them here because they are inextricably linked to the depreciation expense credit adjustment proposed by RMP in this case.

Q. Did UAE raise concerns about RMP's proposed depreciation treatment of the retired plant in in the repowering case, Docket No. 17-035-39?

A. Yes, but for a somewhat different reason. In that docket it was not apparent to me that RMP's proposed depreciation treatment would result in the undepreciated balances of the retired plant being frozen until the next rate case. However, in that case I recommended that any approval of the Company's repowering proposal be made conditional on a reduction to the authorized rate of return on common equity applied to the undepreciated balance of the retired plant. I pointed out that since RMP's cost of capital will change over time, the allowed return on the unamortized balance of the retired plant should be reset as a part of subsequent general rate cases by maintaining a 200 basis point differential relative to the return on equity approved in those cases. I further suggested that to accomplish this it may be more appropriate to convert the undepreciated balances of the retired assets into a regulatory asset, to better track them over time, rather than rebooking them into the accumulated depreciation reserve as proposed by RMP.[21] In its final order in the repowering docket, the Commission reserved the issue of the appropriate return on the retired assets for the next general rate case.[22] Thus, it appears to me that the matter of how the retired assets are to be tracked and depreciated remains an open question.

I do not see it as necessary in *this proceeding* for the Commission to resolve the issue of how the retired assets are tracked and depreciated. That can be done in the depreciation docket. The implication for this case is for the Commission to recognize that denying RMP's deferral request does not mean that customers must forego receiving any credit for the depreciation expense in current rates associated with the retired assets. Rather, this credit should properly be recognized as a credit against the implicit balance of the retired assets in the depreciation docket.

[21] Docket No. 17-035-39, Response Testimony of Kevin C. Higgins, lines 893-903.
[22] Docket No. 17-035-39, Report and Order issued May 25, 2018 at 26.

Q. You noted that RMP has an alternative proposal if the Commission denies the Company's deferral request. What is your response to RMP's alternative proposal?

A. I recommend that the Company's alternative proposal be denied for the same policy reasons that the Commission should deny the Company's primary request for deferred accounting. Under its alternative approach, RMP requests authority to implement an exception to the EBA to remove the incremental benefits of the Repowered Projects and Leaning Juniper until the rate effective date of the Company's next general rate case. That is, the alternative proposal seeks to neutralize the effects of the 100% pass-through EBA as it pertains to the twelve repowered wind plants. As I stated with regard to RMP's primary proposal, the Commission should not impose a new single-issue ratemaking device to neutralize the effects of any temporary NPC benefit to customers from the incremental repowered output, as the temporary benefits are a consequence of having adopted the EBA in the first place at RMP's request. Moreover, implementing the alternative proposal would also introduce undue complexity into Utah ratemaking.

IV. LEANING JUNIPER AND EBA TREATMENT OF NEW GENERATION RESOURCES IN GENERAL

Q. Since the repowering of Leaning Juniper was denied preapproval by the Commission, does that present any special concerns with regard to RMP's requested deferral?

A. Yes, I believe it does. The prudency of Leaning Juniper will be decided in the upcoming general rate case. If the repowering of Leaning Juniper is determined to be imprudent, then, even if the Company's requested deferral for the eleven Repowering Projects is approved, any deferred costs associated with the Leaning Juniper repowering should not be recovered from customers. Notwithstanding my primary recommendation to deny RMP's deferral request, if the Commission approves a deferral for the eleven Repowering Projects, the requested deferral for Leaning Juniper should be specifically rejected in light of the Commission's decision to deny preapproval of that project due to its inferior economics and the associated risk to customers.

Q. If the costs of repowering Leaning Juniper are disallowed in the general rate case, what are the implications for the EBA?

A. If the costs of repowering Leaning Juniper are disallowed in the general rate case, then it would not be reasonable to flow through to customers the benefit of any incremental increase in low-cost energy from the repowering investment in Leaning Juniper, either in base rates or in the EBA. This course of action would require an annual adjustment to the EBA to remove the incremental Leaning Juniper generation for the remaining life of the project.

An adjustment would also be required to address the benefits that would have flowed through the EBA to customers prior to the general rate case disallowance. Since, technically, the EBA is a deferral mechanism, the removal of EBA benefits (or costs) from a resource that is ultimately disallowed would perhaps best be treated as a true-up to the EBA deferral.

Prior to the filing of this case, there appears to have been only one Company generation resource, Lakeside 2, that came into service prior to being included in base rates (either through a general rate case or a major plant additions case) since the adoption of the EBA. In that instance, Lake Side 2 came into service in May 2014, but was not included in base rates until the rate effective period starting September 1, 2014. However, its output starting in May 2014 was included in the EBA.[23] The Commission (implicitly) approved the inclusion of Lake Side 2 in rate base in its Report and Order issued August 29, 2014 in Docket No. 13-035-184, which was fairly close in time to the initial inclusion of Lake Side 2 energy costs in the EBA deferral.

Consequently, with the exception of Lake Side 2, which was not controversial as to prudence, it apparently has not been necessary before now for the Commission to rule on the appropriate EBA treatment for new Company resources for which prudence has not yet been determined.

Q. Do you have a recommended EBA treatment for Company generation resources that come into service prior to being included in base rates?

A. It strikes me that the most practical approach would be to include the energy output from such facilities in the EBA calculation on a conditional basis. If any such facilities are later found to be imprudent either in a general rate case or a major plant additions case, the prior energy generation from such facilities could be adjusted out of the EBA in the form of a true up to the EBA deferral.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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[23] *See* RMP Response to UAE Data Request 3.4, included in UAE Exhibit 1.1.