BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A SIGNIFICANT ENERGY RESOURCE DECISION AND VOLUNTARY REQUEST FOR APPROVAL OF RESOURCE DECISION	))))))))))	**DOCKET NO. 17-035-40** **Exhibit No. DPU 4.0 R-SUP, 4.0 SR** **Surrebuttal and Supplemental Rebuttal Testimony** **David Thomson**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Surrebuttal and Supplemental Rebuttal Testimony of

David Thomson

April 17, 2018

<u>Introduction</u>

Q. Please state your name and occupation.

A. My name is David Thomson. I am employed by the Utah Division of Public Utilities ("Division") as a Utility Technical Consultant.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84111.

Q. Did you previously file Direct Testimony in this Docket?

A. Yes.

Q. What is the purpose of your Testimony?

A. The purpose of my testimony is to comment, as discussed below, on certain parts of the rebuttal testimony of Rocky Mountain Power (Company) witness Ms. Joelle R. Steward. I do not comment on her Supplemental Direct testimony but will briefly comment on her Second Supplemental Direct testimony

My silence on any recommendations given in either Direct, Rebuttal, Supplemental Direct, or Second Supplemental Direct Testimony of those involved in this Docket should not be interpreted as support or disagreement.

Q. In her rebuttal testimony Ms. Steward states, "Although the Company can request the use of a future test year, the Commission may not approve one, and parties, including OCS and UAE, have opposed future test years in the past. Thus, it is highly uncertain whether the Company could implement the proposal to use a future test year to fully capture the costs and benefits of the Combined Projects in a single, timely general rate

case (GRC), making timely cost recovery of this investment uncertain."[1] Does the Division agree with this assessment?

A. No. The Commission in the last three general rate cases approved the future test periods put forth by the Company in its GRC filings. They were future test years of approximately 18, 15, and 18 months. Only the first of the last three GRC test periods was opposed and opposition parties since then have stipulated to the 15 and 18 month test periods. Thus, while stipulations cannot be used as precedent, from this history it appears that it is not highly uncertain but highly likely that a future test period would be used to capture the costs and benefits of the Combined Projects in a single, timely GRC.

Q. What is your response to Ms. Steward's concerns about filing a rate case July 1, 2019, using a future 2020 calendar year test period?

A. Ms. Steward is concerned that since the Combined Project investment won't go into service until late 2020, new rates using a calendar year 2020 test period would only reflect potentially one or two months of the investment using the Commission's traditional thirteen-month average rate base. The Company would need to immediately file another rate case in order to get the all costs in rates.[2]

In the years immediately preceding Docket Nos. 17-035-39 and 17-035-40, the Company used GRC filings to recover new rate base costs in rates, even if it required the Company to immediately file another rate case. DPU Exhibit 4.1 R-SUP, 4.1 SR illustrate this approach. Looking at the exhibit you can see that for three of the four-year periods from 2011 to 2014

[1] See Supplemental Direct and Rebuttal Testimony of Joelle R Steward page 7; lines 149-154.
[2] See Supplemental Direct and Rebuttal Testimony of Joelle R. Steward page 8; lines 160-164.

shown, the Company filed GRCs. The GRC filed February 15, 2012 came soon after the GRC filed January 24, 2011. All three were filed with significant future test year projected rate base increases of approximately $3.5 billion, $2.5 billion, and $2.4 billion for GRC filings in Docket Nos 10-035-124, 11-035-200, and 13-035-184 respectively. Company testimony in these Dockets notes that new asset additions were a significant driver for the GRC filing for rate recovery. There is nothing extraordinary about the acquisition of the wind and transmission projects that would necessitate different treatment.

In DPU Exhibit 4.2 R-SUP, 4.2 SR, I have provided the Company's response to OCS Data Request 13.1. This response notes the resource acquisitions of Cholla, Craig, Hayden, and Chehalis power plants were recovered through rate case filings. No RTM-like mechanism was requested by the Company nor established by the Commission for these acquisitions. Though other approaches for including infrastructure additions in rates might exist,[3] the standard regulatory model provides ample opportunity for recovery and recognizes that regulatory lag is part of the broader regulatory compact.

A GRC is the ordinary method for including infrastructure additions in rates. Future test years and other mechanisms have softened the regulatory lag that sometimes results from this practice. Creating yet another mechanism in this case is unwise. Following the ordinary course of business allows a more regular prudence review and better synchronizes the projects' costs and benefits for ratepayers.

[3] See e.g. Docket No. 11-035-200 and Docket No. 13-035-184.

Q. Mrs. Steward says that in your Direct Testimony you do not explain your rationale or justify your recommendation for the Commission to use an accounting order without an interest carrying charge. What is your response to this observation?

A. Though stipulations generally are not precedential, there are a number of instances where carrying charges have been modified or not included. The GRC filing in Docket No. 11-035-200 was settled through stipulation and Commission order. In that Docket the Company received authorization to defer costs on a number of items as explained here and below. Per the settlement and order, the Company was authorized to defer the costs related to the decommissioning of the Carbon plant. No carrying charge was provided for in the stipulation.

Also in that same Docket, the Company was authorized to defer costs incurred for Naughton development. No carrying charge was provided. The Company was also authorized deferred accounting in conjunction with its FERC rate case in Docket No. ER11-3643-000. The stipulation said the FERC deferral account would not accrue a carrying charge.

Recovery of the Klamath relicensing and process costs were authorized for amortization in rates from October 12, 2012 through the end of calendar year 2022 with a carrying charge at the authorized long-term cost of debt. This was a recovery of actual costs and not a deferral of costs. Since carrying charges would accrue, the net unrecovered relicensing and process costs were to be excluded from rate base in future rate case proceedings.

On another non-deferral matter in the above Docket No. 11-035-200, it was agreed that any difference between base Renewable Energy Credits (REC) revenues and actual REC revenues as determined by the Commission for calendar year 2014 should be recovered or returned over a two-year period from the effective date of the approved rate change to collect or refund such balance, with no carrying charges during such two-year collection or refund period.

The GRC filing in Docket No.13-035-184 was settled through stipulation and Commission order. As with the previous GRC, the Company received authorization to defer costs on a couple of items as explained here and below. It was agreed that if the Company did not obtain an amended permit in 2014 that would allow it to continue to operate Naughton Unit 3 as a coal-fueled resource through December 31, 2017, and parties would not oppose a deferred accounting order dealing with the revenue requirement impact of not obtaining the permit. No carrying charges for the deferral were provided for in the stipulation.

A deferred accounting order was authorized to defer Energy Imbalance Market (EIM) related operations and maintenance expenses after September 1, 2014 and also depreciation expense related to capital investments necessary to implement EIM recorded after September 1, 2014. Any deferral of EIM-related labor costs would be limited to positions created solely as a result of the Company’s participation in the EIM in excess of the full time equivalent employee positions, reflected in the Company's direct filing in that rate case. No carrying charges for the deferral were provided for in the stipulation.

The settlement stipulation and order for the Deer Creek Mine closure in Docket No. 14-035-147 are very complex. However there are a number of provisions in the settlement that have carrying charges and some that do not. Certain provisions provide for a 6 percent carrying charge for Energy Balancing Account (EBA) type costs. Funded costs and Deer Creek CWIP have a debt interest carrying charge of 4 percent. The $10 million sold mining assets, settlement of the retired medical obligation, Fossil Rock coal leases and fuel inventory get ROR. Deer Creek investment, Preliminary Survey and Investigation costs, closure costs, and the 1974 Pension Trust payment have no carrying charges. When it comes to carrying charges this Docket is a mixed bag and appears to be an outlier.

Many deferred accounting orders in the past have no carrying charges. The above examples support my recommendation that if so ordered, it is not unusual for deferred accounts to have no carrying charge.

Even though the majority of deferred accounting orders mentioned above do not have carrying charges, the Commission may want to allow a carrying charge on the incremental costs savings (zero-cost energy) part of the deferred accounting order because it is a fuel cost item. Fuel cost items in the EBA have a carrying charge. In Direct Testimony, the Division stated that a reasonable carrying charge would be based on the Commission approved carrying charge method.

The PTC creates a benefit by generating a tax reduction through a tax credit.[4] The PTC is not a fuel cost item and should not receive an EBA-like carrying charge.

In the Company's Supplemental Direct Testimony in this Docket the Company revised its RTM carrying charge rate to be consistent with the Commission's Carrying Charge Order in Docket No. 17-035-T02 and Docket No. 15-035-69, which was 4.19 percent. Since those dockets the rate has been revised and is now 4.06 percent.

Q. Would deferred accounting as proposed by the Division calculate the deferral the same as the RTM mechanism?

A. Yes, in her rebuttal testimony Ms. Steward stated the following:

> "Under Mr. Thomson's proposal, the Commission would calculate the deferral in the same way as the RTM. Thus, the deferral of the incremental costs and benefits of the Combined projects would be similar and the accounting treatment would essentially be the same as the RTM."[5]

Q. If deferred accounting provides a proper deferral then why the need for a RTM?

A. There is no need for a RTM. However, Ms. Steward describes three "problems" with deferred accounting.

One purported problem is that a deferral could result in "rate pressure" on customers. I am assuming by "rate pressure" the Company means months or even years of deferral growth creating a large balance that will flow all at once into the next GRC.

[4] See Mr. Jeffery K. Larsen Rebuttal Testimony Docket No. 17-035-39 page 11; lines 246-247.
[5] See Supplemental Direct and Rebuttal Testimony of Joelle R. Steward, Page 11; lines 229-232.

If you look above at my response to interest carrying charges you will note that there are numerous deferrals, some starting five or more years in the past, waiting for rate treatment until the next Company-filed GRC. These deferrals are growing now and will continue to grow until the next GRC filing (the Company anticipates that it will file its next GRC during calendar 2020 with a 2021 test year).[6] The Company has “rate pressures” from these requested and stipulated deferrals but did not request a rate adjustment mechanism nor has it filed a GRC for a number of years. The Company does not need a RTM to alleviate any perceived “rate pressure” from deferred accounting: it could alleviate the “rate pressure” by choosing to file a GRC.

Another problem mentioned by Ms. Steward is that,

> … generally accepted accounting principles do not allow for the deferral of a return on investment that would be collected at some undetermined time in the future. With the RTM, the collection of the return component happens annually as part of the RTM’s regular true-up process. The deferral approach would have the same total overall impact on customers: however, it would lead to complicated separate accounting, increased difficulty in auditing, and delayed inclusion of cost/benefit impacts for both customers and the Company. [7]

Deferral of a return on investment in the deferrals from the GRC Dockets mentioned above also are not allowed under generally accepted accounting principles because their collection is undetermined at the time of the deferral. It is not determined until a GRC sets their collection. The Company seems to have been able to deal with the complicated separate accounting, increased difficulty in auditing and delayed inclusion of cost/benefit impacts of

[6] See Company’s response to Office of Consumer Services Data Request 13.9 dated February 23, 2018.
[7] See Supplemental Direct and Rebuttal Testimony of Joelle R. Steward, Page 12; lines 253-259.

the above GRC deferrals. Also, these so-called problems could be corrected with the filing of a GRC. This problem is not a valid reason for establishing a new rate recovery mechanism.

Finally**,** Ms. Steward argues that the deferral violates the matching principle because the investment cost and the PTCs are deferred, but the power cost benefits flow through the EBA. She states that if my approach is used, the net power cost benefits of the zero-cost energy must be pulled out of the EBA and deferred as well.

If the Commission approves the repowering and a deferral, the Division would not object to deferring the net power cost benefits as part of a Commission approved deferred accounting order until the next rate case. However, this non-objection would depend upon a proper method for assessing the net power cost benefits, which could prove difficult.

Q. In her Second Supplemental Direct Testimony, did Ms. Steward change the Company's proposed ratemaking treatment for interim recovery of costs for the projects through the RTM?

A. No. The Company continued to propose recovery through the RTM. Absent an RTM, the Company continued to recommend symmetrical treatment of the costs and benefits of the projects by excluding net power costs benefits from the EBA if costs are not deferred or otherwise reflected in rates.

Q. Does the Division still maintain that a RTM is not necessary?

A. Yes

Q. What is the Division recommending?

A. If the Commission approves the wind and transmission projects as proposed by the Company, the Division continues to recommend that the Commission require a GRC for ratemaking associated with those projects.

Q. Does this conclude your surrebuttal and supplemental rebuttal testimony?

A. Yes.