State of Utah
Department of Commerce
Division of Public Utilities

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ACTION REQUEST RESPONSE

To: Utah Public Service Commission

From: Utah Division of Public Utilities

Chris Parker, Director

Artie Powell, Energy Section Manager

Charles Peterson, Utility Technical Consultant

Date: May 24, 2016

Re: **Approval Recommendation**

Docket No. 16-035-T06, etc.

RECOMMENDATION (APPROVE)

The Division of Public Utilities (Division) reviewed the application and work papers in the referenced matter, submitted interrogatories, and discussed several questions with representatives of Rocky Mountain Power (RMP or Company). Based on this review, the Division recommends that the Commission approve the Company's avoided costs rates for Schedule 37 qualifying facilities. The Division has two additional recommendations regarding future filings. First, in a future filing the Company should change tariff language to use a single reference to on peak hours. Second, edit a footnote in certain work papers to match the calculations in the worksheet.

ISSUE

As ordered by the Commission in Docket No. 08-035-78, Rocky Mountain Power (RMP or Company) filed its update to Schedule 37, Avoided Cost Purchases From Qualifying Facilities, on

April 29, 2016, requesting an effective date of July 1, 2016. The Commission issued an Action Request and a Supplemental Action Request to the Division respectively on April 29, 2016 and May 19, 2016. The initial Action Request came with a due date of May 16, 2016. The Division, however, requested, and the Commission granted, an extension to May 24, 2016. The Action Request directs the Division to complete and report on a general review of the Company's application and on specific questions regarding several modeling inputs. The Division's analysis, review, and recommendations are discussed herein.

DISCUSSION

In its application, the Company proposes updates to certain model inputs to the calculation of Schedule 37 rates and the corresponding avoided cost schedules in the tariff. Specifically, the Company proposes updates to the official forward price curves for natural gas and electric prices; integration costs; the capacity contribution factors for solar and wind qualifying facilities; and the deferrable resource. The Company also proposes modifying the definition of Solar Facility in the tariff. A summary of the effects of the modeling changes is reflected in Table 1.

Table 1: Summary of Avoided Cost Changes—Percentage DECREASES in the 15-Year Levelized Price

	On Peak		Off Peak	
	Winter	Summer	Winter	Summer
Base Load	-5.73%	-12.80%	-5.75%	-9.88%
Fixed Solar	-13.18%	-19.95%	-6.39%	-11.05%
Tracking Solar	-13.64%	-20.14%	-6.24%	-10.80%
Wind	-7.54%	-15.47%	-1.22%	-6.15%

Updates to Deferrable Resource

The 2015 IRP preferred portfolio adds a resource in 2028. The Company's 2015 avoided cost update, used as a deferrable resource a 423 MW east-side resource. In the current avoided cost update, consistent with the Company's 2015 IRP Update, the Company blends an east (635 MW) and west (477 MW) side resource, for the deferrable resource. Given the change in the preferred portfolio, the Division believes the Company's representation of the deferrable resource is reasonable. A comparison to the Company's 2015 avoided cost filing shows an increase in the capacity weighted costs of approximately 14%. An increase in the capacity costs would, everything else equal, tend to increase avoided costs.

Commission Questions Regarding Certain Model Inputs

On May 19, 2016, the Commission sent the Division a Supplemental Action Request directing the Division to investigate certain model inputs:

> **[Question 1]:** Row 36 of the Appendix 1, Table 7 spreadsheet identifies a Frame "F" x 1 SCCT East Side Resource (5,550') and row 31 identifies Table 6.2 of the 2015 IRP as the data source for cells C37:C44. Commission staff was unable to identify a Frame "F" x 1 SCCT East Side Resource at an elevation of 5,550' in Tables 6.1 or 6.2 of the 2015 IRP and therefore could not validate the SCCT cost information in cells C37:C44. Please identify the source of the Frame "F" x 1 SCCT East Side Resource data in Table 7 and confirm the data is accurate.
>
> **[Question 2]:** Commission staff also observed that the plant capacity costs and the fixed pipeline costs for the East Side, CCCT - DJohns Dry "F", 2x1 resource listed in the Appendix 1, Table 7 spreadsheet, cells C133, D133, C135, and D135, differ from the CCCT Dry "F" 2x1 (5,050') resources found in Table 6.2 of the 2015 IRP, pp. 96-97. Please provide an explanation for these differences and confirm whether the information reported in cells C133, D133, C135, and D135 is correct.

The Division reviewed the implied issues and discussed them with the Company. Through an informal data request, the Company provided the Division with its responses to the Commission's questions:

> **RESPONSE [1]:** The reference to an elevation of 5,550 [feet] in Table 7 of Appendix 1 is a typographical error. The data in Table 7 is for the SCCT Frame "F" x1 at [an elevation of] 5,050 [feet] and should have been labeled as such. With the exception of capital and fixed pipeline costs, the inputs in Table 7 of Appendix 1 are shown in Table 6.2 of the 2015 IRP. Capital costs and fixed pipeline costs for the SCCT were adjusted to reflect a Brownfield Frame "F" x1 SCCT at the Dave Johnston site (consistent with the response to the second observation below). Capital costs were calculated by applying the Brownfield Multiplier from the 2015 IRP, contained in the 2015 IRP workpaper "Tbl 6 1-3 - Total Resource Cost for Supply-Side Resource Options.xlsx" (provided on Disk 1 PUBLIC / Chapter – Appendix Public.zip / Chapter 6 – Options), to the SCCT Frame "F" x1 cost of $937/kW as shown in Table 6.2. Fixed pipeline costs were calculated by multiplying the Brownfield Site Dave Johnston CCCT Dry "J", Adv 1x1 pipeline costs of $12.51/kW-Yr in Table 6.2 by the ratio of the heat rate for the SCCT to that of the CCCT.
>
> A copy of the 2015 IRP workpaper "Tbl 6 1-3 - Total Resource Cost for Supply-Side Resource Options.xlsx" is attached, with calculations added in yellow highlight to show the values contained in Table 7 of Appendix 1.
>
> Of note, the SCCT costs are only used to determine what, if any, portion of the CCCT should be classified as capitalized energy. In this filing, the SCCT costs are

higher than the CCCT so there is no capitalized energy and the SCCT should have no effect on avoided costs.[1]

RESPONSE [2]: Costs for the East Side, CCCT - DJohns Dry "F", 2x1 resource listed in Table 7 of Appendix 1 are taken directly from the Brownfield Site section of Table 6.2 in the 2015 IRP, [Excel Rows 99-100]. It is confirmed that the information reported in [Table 7] cells C133, D133, C135, and D135 contain the correct information from that portion of the IRP table.[2]

The Division has reviewed the Company's explanations and the work papers provided in response to its data request. The Division believes that the adjustments to the SCCT data reflecting a brownfield site or project are reasonable. The Division, therefore, concurs with the Company that the information in Table 7, Appendix 1 of the Company's filing is correct.

Updates to the Forward Price Curves

The Company updated both its natural gas and electric forward price curves. Compared to the 2015 update, Docket No. 15-035-T06, the forward price curve for natural gas prices decreased on average by about 14% over the study period, 2016 through 2033. Similar decreases occurred in electric prices. For example, the Mid-Columbia heavy-load hour prices decreased on average by approximately 22% over the study period. Both decreases, everything thing else equal, would tend to decrease the Company's avoided costs.

The Division notes in the 2015 update, the Company used a single east side forecast to derive the burner tip cost for natural gas. In the current filing, the Company uses a weighted average

[1] Responses to DPU informal data request: Dickman, Brian, PacifiCorp; email correspondence responding to DPU informal data request, May 20, 2016. Editing and reformatting added. For convenience, the Division has included in electronic form the spreadsheet, "Tbl 6 1-3 - Total Resource Cost for Supply-Side Resource Options.xlsx," as an attachment to its Action Request Response. Although the targeted calculations and information are highlighted in yellow, this information is **not** confidential.

[2] *Ibid*. Editing and formatting added.

of an east and west side forecast. As the Company explained to the Division, the Company chose to do so because it was using as a deferrable resource a blend or weighting of an east side and west side resource. The Division concurs with the Company that given a blended deferrable resource, it is reasonable and consistent to blend the two gas forecasts.

Updates to the Integration Costs

The Company proposes updating its integration costs for solar and wind QFs. Over the study period, integration costs declined on average by approximately 42%. The decline in these costs would tend to increase avoided costs.

Updates to the Capacity Contribution Factors

The Company proposes updating the Capacity Contribution Factors for Fixed Solar, Sheet No. 37.5; Tracking Solar, Sheet No. 37.6; and Wind, Sheet 37.7. The changes in the capacity factors are summarized in Table 2.

Table 2: Updates to Capacity Contribution Factors

	Current	Proposed
Fixed Solar	68.00%	34.10%
Tracking Solar	84.00%	39.10%
Wind Facility	20.5%	14.5%

These capacity contribution factors are consistent with the Commission's Order in Docket No. 14-035-140, which was issued June 26, 2015. While Docket No. 14-035-140 was specifically for Schedule 38, the Division believes that these factors should be also applicable to Schedule 37.

Additional Comments

1. Avoided Cost Model Table 3

Table 3 of the Company's application calculates the capitalized energy costs ($/kW-yr) included in the avoided costs. Columns "a" and "b" are respectively the fixed costs for a combined cycle CT and simple cycle CT; column "c" is the capitalized energy costs. The Division notes that the formula calculating column c does not match the description in footnote c. The footnote describes the calculation as "column c is zero if the value in column a is greater than that of column b." The calculation however reverses the relationship between columns a and b:

Table 3: Footnote from Company Application, Table 3

Footnote:	c = 0, if a **>** b
Calculation:	c = 0, if a **<** b

At the time the Company acquires a new resource, in this case 2028, the Company can choose either a simple cycle to run a few hours out of the year to meet peak loads or it can acquire a combined cycle to meet the peak but also to meet energy needs throughout the year. Typically, the capital costs of the combined cycle CT would exceed that of the simple cycle CT but would have a better heat rate and thus a lower operating cost. The Company's IRP preferred portfolio may then choose, as it has in this case, the combined cycle to more efficiently meet both its energy needs as well as meeting peak loads.

The Division understands the purpose of Table 3 is to capture or allocate a portion, 50 percent, of the incremental capital costs as energy costs. In this filing, however, we see that the capital or fixed costs of the simple cycle exceed that of the combined cycle. Thus, given that the IRP chose a combined cycle unit in 2028, there are no incremental capital costs to allocate to energy costs. Therefore, the Division concludes that the Company has correctly calculated the capitalized energy costs in Table 3. The Division notes that it appears that this is the first filing in recent memory where the Company employs an "if" statement in the calculation of Table 3. The Division believes this is appropriate but recommends that for future filings the Company edit footnote c to reflect the actual calculation.

2. Peak Hours (Definition)

In the definitions section of the tariff, Peak Hours are defined as:

> **Peak Hours**
>
> On-peak hours are defined as 6:00 a.m. to 10:00 p.m. Monday through Saturday, excluding holidays.
> Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day and Christmas Day. When a holiday falls on a Sunday, the Monday following the holiday will be the holiday and will be Off-peak.

The Company's tariff alternates between the use of "Peak" and "On-Peak" to refer to on peak hours. Even in the definition we see this alternating reference approach. While this is not a serious issue, the Division recommends that for the next filing, the Company scrub the tariff and make use of a consistent reference.

CONCLUSION

The Division has reviewed the Company's application and the updates to the avoided cost rates and recommends:

1. In future filings the Company should edit footnote c of Table 3 to reflect the correct calculation of the capitalized energy costs.
2. In future filings, the Company should scrub the tariff to use a consistent reference to "Peak" or "On-Peak" when referring to peak hours.
3. The Division recommends that the Commission:
    a. Approve language modifications to the definition of Solar Facility;
    b. Approve the updates to the Capacity Contribution Factors proposed by the Company; and
    c. Approve the avoided cost rates proposed by the Company effective July 1, 2016.

CC Robert Lively, Rocky Mountain Power

Service List

Action Request Response

Division of Public Utilities

Docket No. 16-035-T06

Attachment 1

Tbl 6 1-3 - Total Resource Cost for Supply-Side Resource Options.xlsx

ELECTRONIC COPY ONLY