ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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October 2, 2017

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 Secretary

RE: In the Matter of the Application of Rocky Mountain Power for Approval of Power Purchase Agreement between PacifiCorp and Glen Canyon Solar A, LLC.
Docket No. 17-035-26

In the Matter of the Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Glen Canyon Solar B, LLC.
Docket No. 17-035-28

Dear Mr. Widerburg:

Pursuant the Amended Scheduling Order dated June 20, 2017 in the above referenced matters, Rocky Mountain Power (the "Company") hereby submits for filing its Reply Comments.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Informal inquiries may be directed to Bob Lively, Manager, Utah Regulatory Affairs at (801) 220-4052.

Sincerely,

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Power Purchase Agreement between PacifiCorp and Glen Canyon Solar A, LLC.	Docket No. 17-035-26
In the Matter of the Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Glen Canyon Solar B, LLC.	Docket No. 17-035-28 **ROCKY MOUNTAIN POWER'S REPLY COMMENTS**

I. INTRODUCTION

In accordance with the Amended Scheduling Order issued on June 20, 2017, PacifiCorp d/b/a Rocky Mountain Power ("Company") submits this reply to the comments filed on September 22, 2017, by the Utah Division of Public Utilities ("DPU").

DPU argues that the avoided-cost prices in two qualifying-facility ("QF") power-purchase agreements ("PPAs") between the Company and Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC (collectively "Glen Canyon") contain a material error. Specifically, DPU argues that the model runs used to calculate the avoided-cost prices did not account for a transmission constraint that will materially impact the avoided-cost pricing.[1] DPU therefore recommends that the Public Service Commission of Utah ("Commission") reject the PPAs or require the Company to re-run its models, including the transmission constraint, and report back to the Commission.[2] The Commission could then approve the PPAs, assuming that the new avoided-cost prices are agreeable to the Company and Glen Canyon.[3]

In these reply comments, the Company provides an overview of its avoided-cost modeling and clarifies how transmission constraints are included in the modeling. The Company also describes how the transmission constraint identified by DPU is, in fact, already included in the avoided-cost modeling runs used for the Glen Canyon QFs. Therefore, the material error identified by DPU does not exist.

II. BACKGROUND

On May 1, 2017, the Company filed an executed QF PPA with Glen Canyon Solar A, LLC, along with an application requesting approval of the PPA (Docket No. 17-035-26). On May 3, 2017, the Company filed an executed QF PPA with Glen Canyon Solar B, LLC, along with an application requesting approval of the PPA (Docket No. 17-035-28). The Commission later consolidated the two dockets.

[1] DPU Comments at 4.
[2] DPU Comments at 1.
[3] DPU Comments at 1.

Under the terms of the PPAs, Glen Canyon will sell the Company energy generated by two solar-powered generation facilities located in Kane County, Utah. Together, the facilities have a nameplate capacity of 95 megawatts (MW). The PPAs are for a term of 15 years from the commercial operation date of the facilities. The purchase prices set forth in PPAs were calculated using the methodology approved by the Commission orders issued in Docket No. 03-035-14 and Docket No. 12-035-100.

Glen Canyon proposes to site its QFs in a known transmission-constrained area. This means the only way to interconnect to and deliver power from the Glen Canyon QFs across the Company's transmission system is the Sigurd-to-Glen-Canyon 230kV transmission line (Sigurd-GC line). The Company's merchant function, PacifiCorp energy supply management (ESM), only has 95 megawatts (MW) of rights over the Sigurd-GC line—rights it holds to comply with an obligation to the Arizona Public Service Company (APS) under a legacy transmission contract filed with the Federal Energy Regulatory Commission (FERC).

Based on an apparent misunderstanding of the Company's testimony in Docket No. 17-035-036, DPU asserts that the Company's avoided-cost modeling did not account for the transmission constraint on the Sigurd-GC line resulting from the Company's obligation to hold 95 MW of transmission rights for APS.[4] DPU contends that the avoided-cost pricing should be recalculated because this "material factor" was not modeled.[5] As described below, however, the APS rights were included in the avoided-cost modeling, consistent with the Company's statements in Docket No. 17-035-36.[6]

[4] DPU Comments at 3.
[5] DPU Comments at 4.
[6] DPU incorrectly accuses the Company of providing a misleading response to a data request because the Company indicated that its avoided-cost modeling accounted for known transmission rights, even though DPU claims that the APS contract was not modeled. DPU Comments at 4.

III. REPLY COMMENTS

A. Overview of the Company's Avoided-Cost Modeling.

The Company is required to offer PPAs to QFs that include avoided-cost prices.[7] The essence of avoided-cost pricing is that QFs are paid a rate that reflects the savings the Company would incur—or the costs the Company would avoid—by accepting the QF's output and displacing resources owned or contracted by the Company

The Commission approved the Company's use of the Proxy/Partial Displacement Differential Revenue Requirement ("Proxy/PDDRR") methodology for determining non-standard avoided costs under Schedule 38. The Proxy/PDDRR methodology is used to forecast avoided fixed costs from a proxy resource and to forecast avoided energy costs associated with incremental generation from a particular QF. Avoided fixed costs include avoided capital costs, which are based on the capital cost of a proxy resource expressed as dollars-per-kilowatt. The proxy resource is identified as the next deferrable generating unit in the Company's most recent IRP.

The Proxy/PDDRR methodology also produces a forecast of avoided energy costs associated with a particular QF project. This is achieved by simulating the hourly operation of the Company's system using the Generation and Regulation Initiative Decision Tools (GRID) model. Two GRID runs are performed to calculate hourly avoided energy cost. The first run is the existing utility system plus the planned resources contained in the Company's preferred portfolio in its most recent IRP. The second run is the same as the first run with two exceptions: (1) the operating characteristics of the proposed QF project are added with its energy dispatched at zero cost; and (2) the capacity of the deferred IRP resource is reduced by an amount equal to the capacity

[7] 18 C.F.R. § 292.304(a)(2).

contribution of the QF project. The difference in production costs between the two runs is the avoided energy cost.

The avoided-cost methodology approved by the Commission is a study of the QF's output and the resulting impacts on the Company's generation dispatch. This study assumes the QF resource has secured an interconnection, and it also includes certain high-level assumptions about known transmission constraints and PacifiCorp ESM's transmission rights to better estimate the cost savings of backing down other Company resources. In other words, when running dispatch scenarios, the GRID study operates within the basic parameters of the dispatch runs that formed the basis of the Company's most recent IRP. The avoided-cost study does not identify any transmission system upgrades that may be required to address reliability or constraint issues before PacifiCorp transmission can grant the QF's interconnection request or PacifiCorp ESM's transmission service request to deliver the QF's power to load. That is the role of the interconnection and transmission studies.

In addition, the GRID model includes transfer capability based on PacifiCorp ESM's historical short-term and non-firm reservations. This includes capacity reserved on the Company's transmission system as well as capacity reserved on the transmission systems of other utilities. The GRID model does not distinguish between network and point-to-point rights, between the Company and third-party transmission systems, or between long-term, short-term, and non-firm transmission capability.

Short-term firm and non-firm transmission rights are reflected in the GRID model based on the average level of historical short-term and non-firm transmission reservations between each pair of transmission areas in the GRID model and are included in each hour of the study. The

GRID model does not include any wheeling costs or transmission loss obligations associated with the use of these transmission rights.

In the case of Glen Canyon's QFs, the GRID study modeled PacifiCorp ESM's 95 MW of rights over the Sigurd-GC line as available to deliver the output of the Glen Canyon QFs. This assumption was included because, as discussed above, the avoided-cost pricing model reflects certain high-level assumptions about PacifiCorp ESM's transmission rights, and it assumes—for purposes of estimating the cost savings of backing down other PacifiCorp resources—that those rights will be used to deliver QF power. As describe more fully in the briefing and testimony in Docket No. 17-035-36, the fact the avoided-cost study modeled 95 MW of available transmission does not mean that the interconnection study will not identify network upgrades necessary to interconnect the QFs. The two process are separate and distinct, and the transmission assumptions used in the avoided-cost modeling will likely be different from interconnection and transmission studies.

B. Modeling transmission in the Glen Canyon QF avoided cost studies.

The Company performed two avoided-cost studies for Glen Canyon, one for each QF. First, in August 2016, the Company prepared an avoided-cost study for the Glen Canyon A project, which was modeled as a 74 MW resource. Second, in December 2016, the Company prepared an avoided-cost study for the Glen Canyon B resource, which was modeled as a 21 MW resource. In addition, the Glen Canyon B avoided-cost study also assumed that Glen Canyon A was a 68 MW resource, not 74 MW. Thus, in the Glen Canyon B study, the total capacity for both QFs was 89 MW. Before executing the PPAs, Glen Canyon A was modified back to 74 MW at Glen Canyon's request.

The avoided-cost pricing for Glen Canyon A included 20 MW of short-term firm and non-firm transfer capability out of the Pinnacle Peak-Glen Canyon ("PP-GC") transmission area in

which the Glen Canyon QFs are proposed to be located. The avoided-cost pricing for Glen Canyon B included 18 MW of short-term firm and non-firm transfer capability out of that transmission area. The pricing for Glen Canyon B was based on historical data from the 48 months ending June 2016, while that for Glen Canyon reflected historical data from the 48 months ending December 2015.

In addition, the avoided-cost study for both Glen Canyon QFs included the APS' transmission rights DPU referenced in its comments. APS has the option, at its sole discretion, to schedule resources across the Company's system from two locations, represented in GRID as the Four Corners and PP-GC transmission areas. The GRID model does not account for the optionality in APS' rights because GRID does not contain that level of detail and nuance on the nature of PacifiCorp ESM's contractual rights. For simplicity, APS' rights are represented in GRID as a reduction in the transfer capability out of the Four Corners transmission area, an assumption that has not changed in many years. Modeling APS' rights on the Four Corners transmission area provides a sufficient level of granularity for the purposes of producing a reasonable estimate of the Company resources that the Glen Canyon QFs would displace, which is the point of the avoided-cost study.

DPU has proposed that the avoided-cost studies be rerun with the additional transmission constraints associated with the APS contract included. To the extent transfer capability is removed from the avoided-cost studies, much of the output of the Glen Canyon QFs would be trapped within the PP-GC transmission area and would not be deliverable to load. If a QF's output is expected to be undeliverable under certain circumstances, then both the QF's output and the estimated avoided cost would be removed from the avoided-cost calculation for those undeliverable periods. This means there is no "zero price" for those undeliverable periods. Rather, the avoided cost and output

for the undeliverable hours are simply removed, which could result in a lower or higher avoided-cost rate.

For example, if undeliverable output was expected to occur during periods when avoided costs were projected to be higher than average, then the average avoided cost of the remaining delivered output would be lower, resulting in a lower avoided-cost price. If, on the other hand, the undeliverable output was expected to occur during periods when avoided costs were projected to be lower than average, then the average avoided cost of the remaining delivered output would be higher, resulting in a higher avoided-cost price. It is likely that undeliverable output would occur under a range of conditions and that the net impact on the avoided-cost price would be small, particularly if the undeliverable output were a small portion of the total hours during the life of the contract.

In the Glen Canyon B QF avoided-cost study, a small amount of trapped energy was identified in Glen Canyon's transmission area when the Glen Canyon B QF was added, bringing the total QF capacity to 89 MW. The associated trapped energy volumes were assumed not to have been delivered to the company, and the proposed avoided costs reflect only the delivered volumes from the Glen Canyon B QF.

Respectfully submitted this 2nd day of October, 2017.

By: 

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CERTIFICATE OF SERVICE

Docket No. 17-035-26 and 17-035-28

I hereby certify that on October 2, 2017, a true and correct copy of the foregoing was served by electronic mail to the following:

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