ACTION REQUEST RESPONSE

To: Utah Public Service Commission

From: Utah Division of Public Utilities
Chris Parker, Director
Energy Section
Artie Powell, Manager
Charles Peterson, Technical Consultant
Jeff Einfeldt, Utility Analyst

Date: September 22, 2017

Re: Docket Nos. 17-035-26 and 17-035-28. In the Matter of the Application of Rocky Mountain Power for Approval of Power Purchase Agreements Between PacifiCorp and Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC.

The Division of Public Utilities ("Division") determined that the two power purchase agreements ("Agreements") between Rocky Mountain Power ("Company") and Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC (collectively the "Developer") are not in the public interest due to questions about whether or not the pricing represents the true avoided cost prices that would hold ratepayers indifferent. The Company failed to include a significant transmission constraint in modeling the avoided costs and pricing the contracts. On this basis, the Public Service Commission ("Commission") could reject the Agreements in their current form. Short of outright rejection, the Commission could order the Company to quickly re-run its pricing models with the correct transmission constraint included and report the results to the Commission soon, perhaps within two weeks. Then the Commission could approve the agreements with the new pricing if the Company and Developer are agreeable to the new prices. However, the Division has not been able to ascertain to what extent this re-pricing might account for, or not, potential additional transmission costs.

Issue

During the first part of May 2017, the Company filed with the Commission applications for approval of power purchase agreements ("Applications") between the Company and the Developer. The Agreements provide for the purchase of energy from the proposed QF facilities to be developed west of Big Water, Utah. The Solar A site ("Solar A") is a proposed 74 MW facility and the Solar B site ("Solar B") is a proposed 21 MW facility approximately 1.02 miles west of Solar A. Solar A was filed in Docket No. 17-035-26 and Solar B was filed in Docket No. 17-035-28. The schedules for both dockets were consolidated in an amended scheduling order issued by the Commission on June 20, 2017 ("Order"). The Order specified that initial comments on the Applications were due by September 22, 2017. This memorandum represents the Division's comments on the Applications.

Discussion

General

Included with the Applications are copies of the Agreements between the Company and Developer (Solar A dated 4/24/2017 and Solar B dated 5/1/2017). The Developer proposes developing two qualifying facilities ("QF") photovoltaic sites in Kane County, Utah near the town of Big Water. The nameplate capacity rating of Solar A is set at 74 MW and Solar B is 21 MW. The Scheduled Commercial Operation Date is September 29, 2019 for Solar A and October 31, 2019 for Solar B. Both sites are still awaiting results of interconnection and transmission availability studies to be performed by PacifiCorp Transmission. The Solar A and B agreements appear generally similar to agreements executed with other QFs. Under the terms of the QF contract, the Developer is not permitted to sell any portion of the net output to parties other than PacifiCorp.

QF Pricing

The Division has reviewed the pricing calculations and believes they generally comply with the method approved by the Commission, with the exception of the omitted constraint discussed below. Since the projects are located in areas remote from major load centers, no avoided line losses are included in the pricing. Additionally, the value of any green tags or renewable energy credits (often referred to as RECs) are retained by PacifiCorp.

However, as a result of testimony in Docket No. 17-035-36, the Division has learned that there appears to be a significant transmission constraint along the transmission line that the Developer would presumably need to interconnect with. In testimony filed on August 31, 2017 by Company witnesses, Rick A. Vail, Kelcey A. Brown, and Daniel J. MacNeil, the Company argues that while it nominally has rights to 95 MW of transmission capacity that might be available to the Developer, it has a contractual obligation with Arizona Public Service (APS) to hold in reserve the 95 MW for APS's potential use during the summer months.[1] Two contracts with APS, dated 1990 and 1995 were filed as exhibits to Ms. Brown's testimony.[2]

With respect to the modeling of the pricing offered in the Agreements, Mr. MacNeil testifies as follows:

> **Q. Why were these APS legacy contract and transmission-service-type limitations not reflected in the avoided-cost study?**
> A. As I described above, the GRID model simply does not contain that level of detail and nuance on the nature of PacifiCorp ESM's contractual rights. That level of granularity is not necessary for the purposes of producing a reasonable estimate of the PacifiCorp ESM resources that the Glen Canyon QFs would displace, which is the point of the avoided-cost study.[3]

[1] The summer months are defined as the four months May 15 through September 15 in Section 3.2.1 of the "Long-term Power Transactions Agreement" between PacifiCorp and Arizona Public Service Company, dated September 21, 1990. This document was included in the Company's response to OCS DR 1.2, in Docket No. 17-035-36.

[2] The Contracts were previously provided without further explanation in the Company's response dated August 7, 2017 in a response to Office of Consumer Services data request 1.2, and August 10, 2017 to Glen Canyon Solar Data Request 1.12 in Docket No. 17-035-36.

[3] Docket No. 17-035-36, Direct Testimony of Daniel J. MacNeil, page 12, lines 274-277.

While the APS contract "nuance" may have been a minor omission in previous studies for QF pricing brought before the Commission, in this case it appears to be a significant material omission in the Company's execution of its pricing studies for these Agreements.

While the Company had previous opportunities to clearly inform the Division and the Developer that the APS contracts were the specific impediment to interconnecting the Developer's projects with firm, year-round transmission service, the Company was vague about the exact nature of the problem. For example, in its August 10, 2017 response to Glen Canyon Solar Data Request 1.6 in Docket No. 17-035-36, in performing its pricing studies for the Developers projects, the Company stated "Instead, GRID economically dispatches the system as a whole based on the information known to be true at that point in time, *including known transmission rights*." (Italics added). There is no mention of the APS contract constraint in this misleading data request response. Indeed, even if someone had knowledge of the existence of the APS contracts, based on this statement one could reasonably suppose that the APS constraint was modeled in GRID, given that the APS contracts have been in existence for over twenty years and are surely known, or should be known, to the Company. The complete Glen Canyon Solar Data Request 1.6 is attached as DPU Exhibit 1.[4]

Based on the Company's admissions in its August 31, 2017 testimony in Docket No. 17-035-36, it is clear to the Division that a material factor was not modeled in the GRID analyses. Therefore the Division concludes that a material error exists in the pricing set forth in the Agreements. The Division cannot at this time conclude that the prices set forth in the Agreements are in the public interest without the Company re-running its models with the correct transmission constraints.

<u>Additional Interconnection and Transmission Issues</u>

The Developer raised concerns the Company will require it to pay excessive costs for interconnection and transmission upgrades.[5] As discussed above, the Company has also

[4] See also the Company's response to Glen Canyon Solar Data Request 1.11(c), included as DPU Exhibit 2. This response seems to obliquely refer to APS contract constraints, but implies that they are included in GRID and suggests that the contracts contain path options.

[5] Docket No. 17-035-36, Glen Canyon Solar's Motion for Preliminary Injunction, page 33.

suggested that the GRID modeling it does to determine pricing may not include all of the cost factors related to transmission connection in this case. This issue is actively before the Commission in Docket No. 17-035-36. Pursuant to the Company's Electric Service Schedule No. 38, Part II.B, the Developer is required to pay for interconnection costs. The validity of the Developer's concern is not yet known since PacifiCorp Transmission has not completed the required interconnection studies. Furthermore, even if the interconnection costs developed by PacifiCorp Transmission are acceptable to the Developer and are higher than the Developer originally expected to pay, based on the discussion above the Division could still not support the pricing in the Agreements as being in the public interest until they are corrected to show the proper transmission constraints. Under the Public Utilities Regulatory Policies Act (PURPA), the Company's existing ratepayers are to be held indifferent to whether the energy is received from the QF developer or from the conventional utility resources. Whatever the interplay between various other rules and factors, this indifference standard is the touchstone by which pricing and interconnection costs must be judged.

Other Comments

The proposed Agreements have a term of 15 years in compliance with the maximum terms specified in Commission Docket No. 15-035-53[6]. The general terms and conditions of the Agreements appear to be generic in nature and are similar to previous contracts. The non-price related conditions within the Agreements appear to be reasonable and consistent with previous contracts.

The general process and terms other than the pricing and interconnection costs and additional transmission costs discussed above, appear to be in accordance with the what the Commission approved in Docket No. 03-035-14 and Docket No. 12-035-100 for purchases from qualifying facilities.

[6] See Commission Order in Docket No. 15-035-53 pg. 21

Conclusion

Based on the foregoing discussion and the material omission in the Company's pricing model, the Division cannot support the pricing set forth in the Agreements as being in the public interest. The Commission may reject the Agreements. Alternatively, the Commission could order the Company to correct its pricing models and bring the results forward for further consideration, assuming the Company and Developer can agree to the new contract pricing.

CC: Bob Lively, RMP
Michele Beck, OCS
Gary A. Dodge, attorney for Glen Canyon Solar

DPU Exhibit 1

PacifiCorp Response to Glen Canyon Solar Data Request 1.6 in Docket No. 17-035-36

Glen Canyon Solar Data Request 1.6

On pages 17-18 of the Motion to Dismiss, you state that "the Company requested FERC approval to modify its FERC-jurisdictional NOA to permit the Company's merchant function . . . to choose *not* to construct and charge customers for these FERC-jurisdictional transmission-driven network upgrades. If the Company's merchant function chooses this option, however, it must limit the operation of its resources through redispatch (or backing down of generation resources) within its existing transmission rights, with QF schedules limited last." Please state whether this "redispatch (or backing down of generation resources) within its existing transmission rights" with respect to energy purchased from a Utah QF is different from the adjustments in generation resources Rocky Mountain Power utilized to provide avoided cost pricing to that QF and, if so, please explain how it is different and state all facts supporting your statement that they are different.

Response to Glen Canyon Solar Data Request 1.6

PacifiCorp objects to this request as vague, ambiguous, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, PacifiCorp provides the following response:

Yes. The redispatch allowed under the network operating agreement (NOA) between PacifiCorp's merchant function and PacifiCorp's transmission function is different from the "adjustments in generation resources" made by the Generation and Regulation Initiative Decision Tool (GRID) in modeling avoided cost pricing.

Redispatch under the NOA is related to the network transmission service that PacifiCorp's merchant function (energy supply management or ESM) takes from PacifiCorp's transmission function to deliver its designated network resources (DNR) to its designated network loads on a firm basis and in accordance with Federal Energy Regulatory Commission (FERC) policies. Generally speaking, DNRs include owned resources or power purchase agreements (PPA). The redispatch permitted under the NOA amendment allows ESM to back down specific resources on specific transmission paths during actual operations to ensure that ESM meets its must-purchase obligations under the Public Utility Regulatory Policies Act (PURPA) while operating within its existing transmission rights. Section 8.1 of the NOA states that the network transmission customer (i.e., PacifiCorp ESM) "will prioritize its scheduled dispatch of the [DNRs] in the constrained area such that schedules of non-PURPA "must-take" resources will be limited before the schedules of any PURPA "must-take" resources, to the extent feasible in accordance with Good Utility Practice, in order to allow PURPA "must-take" power to flow while still maintaining schedules within any transmission limits identified by the Transmission Provider in the constrained area".

PacifiCorp's avoided cost pricing is determined by comparing a GRID run without the qualifying facility (QF) added to the system and one run with the QF added to the system.

All QFs on the system are modeled as "must-take" resources, but the model assumes the QF can be delivered to load using ESM's existing transmission rights without regard to whether or not network upgrades are required to either interconnect or deliver the QF's power to load (or both). GRID does not model the redispatch of ESM's resources under the NOA amendment (meaning specific resources on specific paths). Instead, GRID economically dispatches the system as a whole based on the information known to be true at that point in time, including known transmission rights. PacifiCorp has modeled QF avoided cost pricing using existing transmission rights (without regard to whether the QF power can *actually* be delivered using those rights) since long before FERC approved the NOA amendment because the transmission facilities necessary to interconnect and deliver a QF's power are not known at the time indicative pricing is provided. Given the "must-take" nature of QF power, and without the data required to be able to model changes to the transmission system needed to interconnect and deliver a QF's power, PacifiCorp must assume the power is produced and delivered to load using the existing transmission system. GRID's economic dispatch of the system as a whole with and without the QF is not the same as modeling ESM's back down of a specific DNR to accommodate QF power on a specific transmission path.

The avoided cost calculation assumptions are significantly broader than just the redispatch priorities related to DNRs delivered to network load using PacifiCorp ESM's network transmission service rights. GRID reflects a broader, system-wide view related to the economic optimization of the dispatch of both network and non-network resources. Non-network resources might include, for example, short-term power purchases delivered using point-to-point (PTP) transmission service. The avoided cost calculation also incorporates redispatch related to the operating reserves necessary to ensure the reliable operation of the transmission system, rather than just transmission capacity necessary to serve load. To the extent resources are holding operating reserves, transmission capacity may appear to be available in GRID; however, that transmission capacity must remain available to allow for delivery of operating reserves during reliability events.

The avoided cost calculations contained in GRID are also based on expected resource output and availability. For instance, solar resources rarely if ever operate at their expected maximum output, but instead are represented in GRID as 12x24 shapes, with a single typical day for each month of the year. In reality, solar resources are expected to output up to their interconnection limit, and their transmission service requests reflect that maximum output. As a result, resources that appear to be deliverable in GRID may not be deliverable in all hours in reality.

DPU Exhibit 2

PacifiCorp Response to Glen Canyon Solar Data Request 1.11 in Docket No. 17-035-36

Glen Canyon Solar Data Request 1.11

On page 16 of the Motion to Dismiss, you state that the use of your existing transmission rights to transmit energy purchased from Glen Canyon Solar may constitute "the potential interference with the Company's contractual obligations to a third party under FERC-jurisdictional legacy transmission contracts."

(a) Please identify and describe in detail the nature of this "potential interference."

(b) Please state whether this "potential interference with the Company's contractual obligations" is likely to be referenced or addressed in any manner in a system impact study performed in connection with either an interconnection request or a transmission service request relating to the Glen Canyon Solar projects and, if so, how any such system impact study is expected to reference or address this "potential interference."

(c) Please describe in detail whether this "potential interference" was reflected, recognized or addressed in any manner in the avoided cost pricing runs for the Glen Canyon Solar QF projects. If so, please describe in detail how it was reflected, recognized or addressed. If not, please explain in detail why it was not so reflected, recognized or addressed.

Response to Glen Canyon Solar Data Request 1.11

(a) Please refer to PacifiCorp's Motion to Dismiss at pages 21-23 for a detailed explanation of this issue.

(b) No. PacifiCorp energy supply management (ESM) has reserved sufficient transmission capacity to fulfill the referenced contractual obligations. To the extent an interconnection request or transmission service request required transmission capacity on the associated paths, it would be incremental to the existing reservations. Other customer existing contractual rights on the path would not be specifically referenced in a system impact study, but the contractual rights would be reflected in available transfer capability (ATC) information or references.

(c) The Generation and Regulation Initiative Decision Tool (GRID) includes PacifiCorp ESM's existing transmission reservations, and it includes a reduction in those rights to account for the referenced third-party obligations. However, the third-party obligations include optionality regarding permissible paths/delivery points that GRID is not capable of resolving. Instead, GRID reflects the entire third-party obligation as a reduction in transmission rights on a single path, which is assumed to reflect typical conditions. While the location of the Glen Canyon Solar qualifying facilities (QF) is on one of the paths allowed under the third-party obligations, it is not on the path reflected in GRID.