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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Rocky Mountain Power's 2014 Avoided Cost Input Changes Quarterly Compliance Filing	**DOCKET NO. 14-035-40** **Utah Clean Energy Comments on Quarterly Compliance Filing—2014.Q2 Avoided Cost Input Changes**

Utah Clean Energy hereby submits comments on Rocky Mountain Power's second quarter, 2014 avoided cost input changes.

DATED: September 22, 4014

RESPECTFULLY SUBMITTED,

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Sophie Hayes
Attorney for Utah Clean Energy

BACKGROUND

In Docket No. 12-035-100, the Commission made findings that changed the way avoided cost pricing is calculated for large renewable Qualifying Facilities (QFs). In that docket, the Commission addressed issues associated with renewable QFs for the first time since its October 31, 2005 Order in Docket No. 03-035-14. In its *Order on Phase II Issues* in Docket No. 120-35-100 (August 16, 2013), the Commission established that avoided costs pricing for large renewable QFs is calculated according to the Proxy/Partial Displacement Differential Revenue Requirement (PDDRR) method, as it is for all large QFs regardless of resource type.[1] The Proxy method is used to determine avoided generation capacity costs[2] while the PDDRR method is used to determine avoided energy costs.[3]

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[1] Docket No. 12-035-100, *Order on Phase II Issues* (Issued August 16, 2013), pages 17-18, 43.

[2] The Commission stated:

> The Proxy method uses the capital cost of a proxy resource to calculate avoided generation capital cost per kilowatt. The proxy resource is identified as the next deferrable resource in the Company's most recent IRP. …The capital cost per kilowatt is calculated using the operating characteristics and payment factor identified in the IRP for this resource, including its IRP reported non-fuel fixed and variable operation and maintenance costs. To convert the proxy plant capital cost, grossed up for revenue requirement, to an annual cost per kilowatt, the method uses the IRP resource payment factor as the basis for the real levelized annual cost of the present value of the investment and adds inflation each year thereafter. The non-fuel variable operation and maintenance costs are converted into an annual cost per kilowatt, using the relevant reported capacity factors…adjusted for inflation, and this amount is added to the annual avoided capital cost calculation. This produces avoided capital costs that increase over time.

Docket No. 03-035-14, *Report and Order* (Issued October 31, 2005), pages 7-8. For wind and solar QFs, capacity payments, based on the foregoing, are adjusted to account for the capacity value of such resources. Docket No. 12-035-100, *Order on Phase II Issues* (Issued August 16, 2013), page 20.

[3] The Commission stated:

> To calculate avoided energy cost, the PDDRR method employs the Company's production cost model, GRID, to simulate the hourly operation of PacifiCorp's utility system. …Two twenty-year 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: the operating characteristics of the proposed qualifying facility are added with its energy dispatched at zero cost and the capacity of the IRP resource is reduced by an amount equal to the QF capacity. The difference in production cost between the two runs is the avoided energy cost.

Docket No. 03-035-14, *Report and Order* (Issued October 31, 2005), pages 8-9.

In its August 2013 Order, in addition to establishing the Proxy/PDDRR method for calculating avoided costs pricing for large renewable QFs, the Commission addressed various issues implicated by applying the Proxy/PDDRR method to variable renewable QFs, including the following: the capacity contribution of renewable resources, integration costs for renewable resources and the hedging and environmental values of renewable resources.[4] The Commission approved interim capacity values for wind, fixed solar and tracking solar resources: 20.5%, 68% and 84%, respectively. The Commission approved inclusion of integration charges for wind and solar resources in avoided cost pricing and provided further guidance on such integration charges

[4] The Commission ordered the following, specifically:

> Pursuant to our discussion, findings and conclusions, we order:
> 1. RECs shall be retained by the QF unless the QF and purchasing utility have agreed by negotiated contract to an alternate REC ownership structure.
> 2. Future requests for indicative pricing for wind QFs under Schedule 38 shall be calculated using the Proxy/PDDRR method.
> 3. When PacifiCorp's IRP planned resources include a cost-effective renewable resource of the same type as the QF, avoided cost capacity payments under Schedule 38 shall be based on the capital costs of the next deferrable resource of the same type in PacifiCorp's IRP planned resources.
> 4. When PacifiCorp's IRP planned resources do not include a cost-effective renewable resource of the same type as the QF, avoided cost capacity payments under Schedule 38 shall be based on the capital costs of the next deferrable thermal resource in PacifiCorp's IRP planned resources.
> 5. All renewable resources included in PacifiCorp's IRP planned resources which are not cost-effective but are required to meet a state's RPS shall be treated as system resources in the calculation of QF energy payments.
> 6. PacifiCorp is directed to perform and file a study calculating capacity contribution for wind and solar resources for the Proxy/PDDRR method using either the ELCC method or CF method considering LOLP.
> 7. When PacifiCorp's IRP planned resources do not include a cost-effective wind resource and pending PacifiCorp's filing of the results of its ELCC or CF study for wind resources, PacifiCorp shall apply a 20.5 percent capacity contribution for wind QFs for the purpose of determining Schedule 38 capacity payments.
> 8. When PacifiCorp's IRP planned resources do not include a cost-effective solar resource and pending PacifiCorp's filing of the results of the ELCC or CF study, PacifiCorp shall apply a 68 percent capacity contribution for Fixed Solar QFs and an 84 percent capacity contribution for Tracking Solar QFs for the purpose of determining Schedule 38 capacity payments.
> 9. A $4.35 per megawatt hour wind integration charge shall be used for calculating Schedule 38 indicative prices for wind QF resources.
> 10. PacifiCorp is directed to apply a $2.83 per megawatt hour solar integration charge for Fixed Solar QF resources and a $2.18 per megawatt hour solar integration charge for Tracking Solar QF resources. These solar integration charges shall be in effect until PacifiCorp files a solar integration study.

Docket No. 12-035-100, *Order on Phase II Issues* (Issued August 16, 2013), pages 43-44.

in its *Order Granting in Part and Denying in Part Rocky Mountain Power's Petition for Review and Clarification* (issued October 4, 2013 in Docket No. 12-035-100).[5]

Regarding the hedging and environmental values of renewable QFs, the Commission included the following in its August 2013 Order:

> We do not dispute the conclusion…that avoided costs based on an actual determination of the expected costs of upgrades to the distribution or transmission system would be consistent with PURPA. We have a difficult time, however, drawing a correlation between avoided distribution and transmission costs that may be projected and tested with a reasonable degree of certainty (e.g., through transmission studies) and environmental risk factors (e.g. costs associated with adapting to changing climate) based upon divergent and speculative projections.
>
> Rather, to the extent potential costs associated with environmental risks and hedging can be projected and factored into Company decision making, they should be accounted for in PacifiCorp's IRP modeling and resource portfolio evaluation process where cost, risk and uncertainty are evaluated to identify a least-cost, risk-adjusted, long-term resource plan.
>
> Preparation and review of PacifiCorp's IRP action plan is governed by UCA § 57-17-301, UAC R746-430 and the Commission's order issued in Docket No. 90-2035-01 approving the standards and guidelines for integrated resource planning for PacifiCorp ("IRP Guidelines"). The IRP process outlined in the IRP Guidelines provides a reasonable opportunity to evaluate cost, risk and uncertainty in order to identify a least-cost, risk-adjusted, long-term capacity expansion plan. The IRP process requires the consideration of the environmental risks and fuel price volatility identified by parties in this proceeding. Moreover, the IRP Guidelines at Section 7 of Attachment A state, "Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan."
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> Finally, as pointed out by FERC in the CPUC decision cited above, "a state may separately provide additional compensation for environmental externalities, outside the confines of, and, in addition to the PURPA avoided cost rate, through the creation of renewable energy credits." We believe our policy with respect to REC ownership encourages renewable development without running afoul of the avoided cost principles outlined in PURPA. Thus, for the foregoing reasons, we approve no specific adjustments to value fuel price hedging, fuel price volatility or environmental risk.[6]

[5] Docket No. 12-035-100, *Order Granting in Part and Denying in Part Rocky Mountain Power's Petition for Review and Clarification* (Issued October 4, 2013), page 14.
[6] Docket No 12-035-100, *Order on Phase II Issues* (issued August 16, 2012), pages 41-42 (footnotes omitted).

On August 22, 2014, Rocky Mountain Power (the Company) filed its Quarterly Compliance Filing regarding changes the Company made during the second quarter of 2014 to the models and assumptions used for calculating avoided costs (hereinafter *Q2.2014 Filing*). "Noteworthy changes include removal of an assumed carbon tax from the Company's official forward price curve and updating the GRID model topology to include a new load bubble named Clover between the existing Utah North and Utah South bubbles."[7]

Utah Clean Energy submits these comments on certain changes the Company made to avoided cost pricing modeling assumptions and data inputs. Specifically, Utah Clean Energy addresses the following:

- Removal of an assumed carbon tax from the Company's official forward price curve (OFPC) and fuel cost for net power costs and plant commitment and dispatch decisions;
- Addition of new Clover transmission load bubble in GRID; and
- Updates to integration charges for renewable resources.

Utah Clean Energy also requests that the Commission set a schedule to address any contested issues, including time for a technical conference, discovery, formal comments or testimony and a hearing, if necessary.

COMMENTS

Removal of an assumed carbon tax from the Company's OFPC and fuel cost for net power costs and plant commitment and dispatch decisions.

In Appendix A of the Company's *Q2.2014 Filing*, the Company explains, "Potential environmental costs are excluded from the OFPC and are also excluded from fuel cost for net power costs and plant commitment and dispatch decisions."[8] Utah Clean Energy urges the Commission to find this change inconsistent with its Orders and direct the Company to

[7] Rocky Mountain Power, *Docket 03-035-14—Quarterly Compliance Filing—2014.Q2 Avoided Cost Input Changes* (filed August 22, 2014), Cover Letter page 1 (hereinafter *Q2.2014 Filing*).
[8] *Q2.2014 Filing,* Appendix A page 2.

reincorporate environmental compliance costs into its price curve, net power costs and plant commitment and dispatch decisions (and any other modeling assumptions or data inputs determinative of avoided costs from which these assumptions were extracted).

The Commission's guiding principle is to set avoided cost prices in a manner that is consistent with the Company's planning assumptions in order to benefit from the Integrated Resource Plan's (IRP) consideration of long term cost, risk and uncertainty.[9] Although in the above-cited Order in Docket No. 12-035-100 the Commission disallowed specific adjustments that *increased* the value of mitigated environmental risk, it is correspondingly inappropriate for the Company to make specific adjustments to *reduce* the value of avoided environmental regulatory risk (particularly in light of the Commission's guidance to set avoided costs in a manner consistent with the IRP).

Currently, the IRP presents the Company's best public analysis of the costs and risks associated with the environmental implications of its resource decisions; therefore, to the extent that environmental regulation cost assumptions are used in the IRP, these assumptions should be carried through to avoided-cost pricing. The Commission order very specifically states that *no specific adjustments* should be made to value fuel price hedging, fuel price volatility or environmental risk.[10] In the current case, the Company has very clearly made a "specific adjustment," in a manner that reduces the value of mitigated environmental regulatory risks as modeled in the Company's IRP.

Avoided costs should be a reflection of actual avoidable costs, including costs the Company would otherwise incur in the absence of QF generation, based on its resource procurement decisions, consistent with the long term nature of QF power purchase agreements.

[9] *See supra* note 6.
[10] *Id.*

The IRP may not accurately reflect the full range of environmental costs and risks associated with the Company's resource decisions,[11] but it does represent the most comprehensive, publicly available information that the Company discloses about its forecast of the long term costs and risks associated with its resource decision-making.

The Company includes carbon costs in its IRP analysis as well as in its projections of fuel prices, power prices and net power costs. The Company utilizes carbon costs in justifying its investment decisions. Therefore, the Company should not be authorized to make adjustments removing this important assumption solely for avoided cost purposes. In order to be consistent with resource planning, as well as Company decision-making generally, the Company should restore all avoided costs input assumptions for which environmental compliance costs have been removed back to base case assumptions. In other words, any modeling assumptions or data inputs that were adjusted to exclude carbon or other environmental compliance costs should be restored to include those costs.

Addition of new Clover transmission load bubble in GRID.

Utah Clean Energy recommends that the Commission not acknowledge or permit the Company's alleged transmission-associated price impacts until an evidentiary proceeding determines that it is legally permissible and factually necessary to do so. Utah Clean Energy recommends that the Commission conduct an investigation to evaluate the legal and factual issues associated with an alleged transmission constraint on avoided cost prices.

In its August 22, 2014 filing, the Company stated,

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[11] Renewable QFs offer many risk mitigating benefits to ratepayers. Utilities purchase electricity from renewable QFs, typically through long-term power purchase contracts. Because energy resources such as wind, solar and geothermal have no fuel costs and do not emit pollution or greenhouse gasses, renewable QFs provide valuable long-term risk mitigation against rising fuel costs, fuel price volatility, environmental compliance costs, potential carbon regulation costs and the actual costs of a changing climate. *See e.g.* Docket No. 12-035-100, *Wright Dir. Test.*, pages 6-15 (March 29, 2013).

> On April 29, 2014, PacifiCorp Transmission identified on its Open Access Same-time Information System (OASIS) that there was no remaining south-to-north transmission capacity across the Huntington/Sigurd cutplane in the area of central Utah. Such a transmission constraint is relevant to avoided costs because many of the recently-proposed qualifying facility (QF) projects in Utah are located south of the cutplane while most of the Company's Utah retail load is north of the cutplane. QFs located south of the cutplane must be integrated along with other network resources and *may cause the Company to back down its existing thermal resources if transmission capacity is not sufficient.* In order to reflect this potential impact on avoided costs, the Company added the Clover bubble to the GRID model topology to reflect the Company's transmission rights across the Huntington/Sigurd cutplane. The updated GRID topology will impact avoided costs for potential QFs located south of the cutplane based on the unique generation profile of each QF and the availability of transmission to move energy out of the Utah South bubble in GRID.[12]

Pricing impacts associated with transmission constraints is a relatively new development in avoided costs calculations. In *Pioneer Wind Park I, LLC*, the Federal Energy Regulatory Commission (FERC) found that a proposed curtailment provision in a power purchase agreement (PPA) between PacifiCorp and a wind QF violated PURPA's non-discrimination protections and improperly treated the wind QF as if it were a non-firm transmission customer.[13]

In its Order, FERC concluded, "In response to our decision here, we would expect that the proposed section 4.4(b) curtailment provision will be removed from the draft PPA, and that PacifiCorp and Pioneer Wind will be able to negotiate PPA prices reflective of each party's view as to fluctuation in the value of capacity and energy, and as to the costs avoided by PacifiCorp as a result of the purchase from Pioneer Wind."[14] Following that statement, FERC included a footnote further specifying that, "The parties could, for example, agree to prices that reflect the new transmission project entering service, and also to alternative prices should the new transmission project not enter service."[15]

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[12] *Q2.2014 Filing*, Cover letter pages 1-2 (emphasis added).
[13] *Pioneer Wind Park I, LLC*, 145 FERC P 61215, Para. 37 (December 16, 2013).
[14] *Id.* at Para. 41.
[15] *Id.* at footnote 79.

It is not apparent that the Company's new transmission bubble is consistent with FERC's Order, nor has the Company factually justified its creation within the *Q2.2014 Filing*. Based on the Company's filing, in conjunction with other recent avoided costs filings, the extent to which a new transmission bubble is necessary is unclear. For example, in Direct Testimony on Schedule 37 avoided costs pricing, Company Witness Greg Duvall explained,

> Upon further review the Company believes the transmission constraint will be an issue for all QFs (Schedule 37 and Schedule 38) *once enough resources are located south of the cutplane and capacity constraint is reached. However, the Company does not anticipate this will occur before the 25 MW cumulative cap on Schedule 37 is reached again*. [fn8:] For large QFs priced under Schedule 38, it is important that the GRID model reflect the constraint in the transmission topology to calculate the avoided cost of energy including the impact of backing down existing thermal resources south of the constraint.[16]

The Company has not explained why Schedule 38 pricing should be impacted now, by a new transmission bubble, when it appears that the transmission constraint is still uncertain. According to the Company, resources located in Southern Utah "*may* cause the Company to back down its existing thermal resources if transmission capacity is not sufficient."[17] Because there are legal and factual issues relevant to a determination of whether the Company's avoided costs modeling change is appropriate, it is premature to allow an alleged constraint impact prices for QFs. In addition to the foregoing, the Company has not addressed the extent to which Southern Utah QFs may serve load south of the cutplane, or the extent to which the new energy imbalance market (EIM) will allow the Company to utilize transmission and dispatch generation more efficiently, increase transfer capabilities or simply provide more transparent information about transmission constraints and congestion.[18]

[16] Docket No. 14-035-T04, *Duvall Dir. Test.*, page 19 (July 11, 2014) (emphasis added).
[17] *See supra* note 11.
[18] *See, e.g.* E3, *PacifiCorp-ISO Energy Imbalance Market Benefits* (March 13, 2013), available at http://www.pacificorp.com/about/eim.html.

Utah Clean Energy recommends that the Commission initiate a proceeding to investigate the legal and factual issues associated with the alleged transmission constraint *prior to* permitting the Company to change its modeling for QFs. Consistent with this recommendation, Utah Clean Energy recommends that the Commission direct the Company to remove the new Clover transmission bubble from GRID, pending the conclusion of such an investigation and associated Commission Order.

Integration charges.

Because the Company has not initiated a solar integration study to evaluate the actual costs of integrating solar generation, Utah Clean Energy recommends, as an interim measure, that the Commission permit periodic updating of solar integration charges, consistent with the method initially used to create the currently-approved solar integration charge values.

On reconsideration of its August 16, 2013 Order in Docket No. 12-035-100, the Commission explained:

> In the August Order, use of the wind integration charge as a basis to derive solar integration charges was not intended to be permanent. Rather, in the absence of a solar integration study, we accepted the Utah Division of Public Utilities proposal to apply 65 percent and 50 percent of PacifiCorp's wind integration charges to fixed solar and tracking solar resources, respectively. We therefore directed PacifiCorp to apply a solar integration charge of $2.83 per megawatt hour for Fixed Solar resources and a $2.18 per megawatt hour solar integration cost for Tracking Solar resources based on the wind integration charge of $4.35 per megawatt hour levelized starting in 2013. We further noted these values will remain in effect pending PacifiCorp filing a solar integration study. To that end, we fully anticipate that PacifiCorp will file a solar integration study in the near future.
>
> We agree with PacifiCorp that the solar integration charges require updating. Following the filing of a solar integration study, we intend for the Company to update its solar integration charges for changes in relevant studies or market conditions, similar to what is required for wind integration charges. To that extent, PacifiCorp's request for ongoing updates to solar integration charges is approved.[19]

[19] Docket No. 12-035-100, *Order Granting in Part and Denying in Part Rocky Mountain Power's Petition for Review and Clarification* (Issued October 4, 2013), page 14.

Thus, at the conclusion of Docket No. 12-035-100, solar integration costs for fixed solar resources were set at 65% of $4.35/MWh: $2.83/MWh; solar integration costs for tracking solar resources were set at 50% of $4.35/MWh: $2.18/MWh.

The Commission found that updates to integration charges were necessary in order to remain up to date; however, presumably because the Commission anticipated seeing results of a solar integration study within a short timeframe, the Commission ordered maintenance of the current solar integration charge *values*. However, based on information and belief that a solar integration study is not forthcoming in the near term, and given that the wind integration cost has been updated, Utah Clean Energy recommends that the Commission permit the Company, on an interim basis, to update the imputed solar integration charges consistent with the method employed in Docket No. 12-035-100. In theory at least, this will allow solar integration charges to be kept more up-to-date, along with wind integration charges.

It is fairer to update solar integration charges according to the interim method utilized in Docket No. 12-035-100 than to maintain solar integration cost values based on an out of date wind integration charge. Therefore, Utah Clean Energy recommends the Company utilize the following solar integration values: $2.01/MWh for fixed solar resources (65% of $3.09/MWh) and $1.55/MWh for tracking solar resources (50% of $3.09/MWh) until more accurate and up-to-date information is available.

CONCLUSION

In response to Rocky Mountain Power's *Q2.2014 Filing*, Utah Clean Energy recommends the following:

- The Company should restore all avoided costs input assumptions for which environmental compliance costs have been removed back to IRP base case assumptions.

- Utah Clean Energy recommends that the Commission initiate a proceeding to investigate the legal and factual issues associated with the alleged transmission constraint prior to permitting the Company to change avoided cost modeling. Utah Clean Energy further recommends that the Commission direct the Company to remove the new Clover transmission bubble in GRID, pending the conclusion of such an investigation.
- Utah Clean Energy recommends that the Commission permit the Company, on an interim basis until a solar integration study is complete, to update imputed solar integration charges consistent with the method employed in Docket No. 12-035-100. Thus, Utah Clean Energy recommends the Company update the solar integration charge consistent with the recently updated wind integration charge: \$2.01/MWh for fixed solar resources (65% of \$3.09/MWh) and \$1.55/MWh for tracking solar resources (50% of \$3.09/MWh).

Finally, Utah Clean Energy requests that the Commission set a schedule to address any contested issues, including time for a technical conference, discovery, formal comments or testimony and a hearing, if necessary.

DOCKET NO. 14-035-40

CERTIFICATE OF SERVICE

I CERTIFY that on the 22nd day of September, 2014, a true and correct copy of the foregoing was delivered upon the following as indicated below:

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