Mark C. Moench (2284)
Yvonne R. Hogle (7550)
Rocky Mountain Power
201 South Main Street, Suite 2300
Salt Lake City, Utah 84111
Telephone No. (801) 220-4050
Facsimile No. (801) 220-3299
mark.moench@pacificorp.com
yvonne.hogle@pacificorp.com

Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger Than Three Megawatts	Docket No. 12-035-100 **ROCKY MOUNTAIN POWER'S POST HEARING BRIEF**

Rocky Mountain Power, a division of PacifiCorp ("RMP" or "Company"), submits this Post-Hearing Brief in accordance with the Public Service Commission of Utah's ("Commission") request at the hearing held in this docket June 6, 2013.

I. INTRODUCTION

Based on both substantial evidence and the law, the currently-effective Market Proxy ("Market Proxy") methodology for qualifying facilities larger than three megawatts ("QF") should be discontinued in favor of a modified partial displacement differential revenue requirement method. The Commission should change the way the capacity contribution portion of the avoided cost payment is calculated consistent with the Company's "exceedance approach" (as defined below). Further, no compelling evidence has been provided by any party to support a change to the timing of capacity contribution payments. Consistent with federal and Utah laws, the Commission should continue to link the timing of capacity contribution payments with the timing of when the next deferrable resource would actually be deferred. Integration costs should be included in the calculation of avoided cost prices for wind and solar resources because both are intermittent and cause the Company to incur such costs. In addition, parties' recommendations that avoided costs should include fuel, greenhouse gases ("GHG") and climate change adders are both unsubstantiated and not permitted under current federal and Utah laws. Finally, it is good policy for renewable energy credits or certificates ("RECs") created from the energy the Company is obligated to purchase from QFs to be owned by the Company for the benefit of its customers.

II. ARGUMENT

A. The Commission Should Discontinue the Use of the Market Proxy Method Because it Produces Prices that Exceed Avoided Costs as Defined Under the Public Utility Regulatory Policies Act of 1978.

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Company is required to purchase electricity offered by QFs at rates that are just and reasonable to customers and are no greater than the incremental cost the Company would otherwise incur to generate the energy itself or purchase it from another party.[1] The incremental cost is the maximum price the Company is obligated to pay to ensure ratepayer indifference, i.e., that customers do not pay any more for energy supplied by a QF than they would for energy generated by the Company itself or purchased by the Company from another source.[2] The currently effective Market Proxy method yields prices that are higher than the Company's avoided costs and should, therefore, be discontinued by the Commission. The methodology is inconsistent with PURPA and is not in the public interest.

[1] Pub L. No. 95-617, 92 Stat. 3117 (1978).

[2] FERC *Notice of Proposed Rulemaking, Administrative Determination of Avoided Costs, Rates for Sale of Power to Qualifying Facilities, and Interconnection Facilities*, Docket No. RM88-6-00; IV F.E.R.C. Statutes and Regulations (CCH) ¶ 32,457 (1988).

The Market Proxy method was the first of two methods approved by the Commission for pricing wind QFs approximately eight years ago in its order issued October 31, 2005 in Docket No. 03-035-14 ("2005 Order") when the Company was a) actively seeking to acquire renewable resources, b) conducting renewable requests for proposals ("RFP") and c) planning to continue to acquire renewable resources on a regular basis for the then-foreseeable future.[3] Duvall Direct/3, ll. 54-56.

The Commission linked the Market Proxy method to the concept of an Integrated Resource Plan ("IRP") target for renewable resources that originated in the Company's 2004 IRP. According to the 2004 IRP, the Company planned to acquire 1,400 megawatts of new wind resources by issuing frequent system-wide RFPs for wind resources. Duvall Direct/7, ll. 143-145. The Commission found that a "Proxy approach for determining the avoided generation capacity and energy costs associated with a wind QF is appropriate for meeting the IRP planned acquisition of cost effective wind resource, the IRP target amount."[4] Although the Commission defined the IRP target amount in the 2005 Order as the IRP planned acquisition of ***cost effective*** wind resources,[5] in Docket No. 12-2557-01 in its order issued September 20, 2012 ("2012 Order'), the Commission clarified that "as long as wind resources are present in the IRP, the Company should use the Market Proxy method to determine avoided cost pricing for wind QFs". Duvall Direct/8, ll. 176-178. The 2012 Order was silent on the matter of "cost effectiveness", but the Commission recognized that circumstances can change over time and invited parties to pursue changes to the calculation of avoided costs pricing.[6]

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[3] See *In the Matter of the Application of PacifiCorp for Approval of an IRP Based Avoided Cost Methodology For QF Projects Larger Than One Megawatt,* Docket No. 03-035-14, Report and Order, October 31, 2005.
[4] 2005 Order, at 18.
[5] *Id.*
[6] *In the Matter of Blue Mountain Power Partners, LLC's Request that the Public Service Commission of Utah Require PacifiCorp to Provide the Approved Price for Wind Power for the Blue Mountain Project,* Docket No. 12-2557-01, Order on Request for Agency Action, September 20, 2012, p. 10-11.

Since 2005, conditions have changed and require a corresponding change to the calculation of avoided costs pricing. For example, the Company is not actively seeking, or conducting any system-wide RFPs, to acquire any new resources, renewable or otherwise, and the Company expects these conditions to persist for many years. Continued use of the Market Proxy method is not in the public interest because it is based on a flawed "IRP target" for renewable resources which does not take into account the timing of wind resource additions, includes wind plants that are not cost-effective, and does not reflect the Company's ability to use Utah wind QFs to satisfy other states' RPS requirements. Duvall Direct/15, ll. 321-325.

Utah Clean Energy's ("UCE") claim that the issue of "whether or not renewable resources are added solely for RPS compliance purposes, or whether they are found to be in the public interest for other reasons, should be determined in the IRP docket after a thorough review of costs and risks" is at best vague and at worst selective. Wright Rebuttal/5, ll. 77-79. It appears that UCE is proposing that a determination on this issue be made in the 2013 IRP proceeding before allowing the Company to rely on the results in this case. However, UCE has no problem relying on other results in the 2013 IRP to advance its position on other issues in this case. Further, the Commission did not condition approval of the avoided cost methodology in 2005 upon any Commission-determined issue within the 2004 IRP and it should, likewise, not do so here with respect to the 2013 IRP. Regardless, it appears that the Commission did not contemplate the factors set forth above when it established the IRP target in 2005. The Commission appeared to have focused on circumstances that existed at the time the Company filed the 2004 IRP. Abandoning use of the Market Proxy method is the only way to ensure that avoided cost pricing evolves with current conditions and reflects accurate, actual avoided costs at any given point in time.

B. Use of the Proxy/Partial Displacement Differential Revenue Requirement, with Certain Modifications, Will Produce Avoided Costs Pricing that Reflects Accurate, Actual Avoided Costs, Consistent with PURPA and the Ratepayer Indifference Standard.

The second methodology approved by the Commission under the 2005 Order for pricing wind QFs was the Proxy/Partial Displacement Differential Revenue Requirement ("PDDRR") method. The Commission ordered that it be used once the Company reached the "IRP target". Duvall Direct/15, ll. 319-321. The Commission noted that "once the next deferrable IRP resource is no longer a wind resource, wind QF pricing will be based, as it is for non-wind QFs, on the Proxy/PDDRR methods ...."[7] This is precisely the situation currently reflected in the 2013 IRP. The next deferrable resource in the IRP is a combined cycle combustion turbine ("CCCT"). The Company does not plan to add additional wind resources until 2024 and the only wind resources in the IRP were selected solely to comply with RPS requirements. It follows that the Proxy/PDDRR method should be used instead of the Market Proxy method given current circumstances. Further, the Office of Consumer Services ("OCS"), the Division of Public Utilities ("DPU") and Kennecott Utah Copper and Tesoro Refining and Marketing Company ("KUC/Tesoro") all agree with the Company that the Proxy/PDDRR method should be used in favor of the Market Proxy method.[8] Thus, the Commission should approve the Proxy/PDDRR method as recommended by the Company, OCS, DPU and KUC/Tesoro, with certain modifications that are necessary to account for new information and circumstances that were not contemplated in 2005.

[7] *In the Matter of the Application of PacifiCorp for Approval of an IRP Based Avoided Cost Methodology For QF Projects Larger Than One Megawatt,* Docket No. 03-035-14, Report and Order, October 31, 2005, p. 22.
[8] Tr. 171, ll. 11-15; Tr. 191, ll.15-16 and Tr. 192, ll. 2-6; Tr. 221, ll. 23-25 and 222, ll. 1-4.

1. <u>The Commission Should Approve the Exceedance Approach to Calculate the Capacity Contribution Portion of Avoided Costs Because it is the Only Method that Measures Reliability During the Company's System Peak</u>.

In the 2005 Order, the Commission determined that the high load hour ("HLH") capacity factor of 35 percent for a wind resource should be used to assign a capacity value to wind resources. Duvall Direct/16, ll. 339-342. However, the Commission noted the DPU's recommendation that "the percentage of capacity payment should be updated as better information becomes available." Duvall Direct/17, ll. 348-350. To address this issue, the Company conducted an "exceedance approach" study, explained in detail in Exhibit RMP__ (GND-1) in Mr. Duvall's direct testimony. Specifically, the study measured the actual capacity contribution provided by the Company's wind portfolio over the 2007-2011 period. Duvall Direct/17, ll. 351-354. For solar, the Company calculated the capacity contribution using solar profile data produced by the National Renewable Energy Laboratory ("NREL"). Duvall Direct/17, ll. 354-356. The concept behind this methodology is to measure the level of intermittent capacity necessary to provide the same level of reliability in peak hours as expected from the next deferrable resource in the IRP, a CCCT. Duvall Direct/Exhibit RMP __ (GND-1), p.1. The Company expects the full output of the next deferrable resource in the IRP to be available in more than 90 percent of peak load hours. Duvall Direct/Exhibit RMP __ (GND-1), p.1.

The exceedance study showed that the contribution of wind resources in meeting the highest 100 hours of summer load, with a 90 percent confidence level, is 4.1 percent of nameplate capacity, and the corresponding capacity contribution of solar resources is 11.5 percent for energy-oriented facilities and 25.9 percent for peak-oriented and tracking facilities. Duvall Direct/17, ll. 364-367. The Company uses this approach to calculate avoided costs of renewable resources in Idaho and also used it to determine the capacity contribution of intermittent resources in the 2013 IRP. Duvall Direct/17, ll. 360-362. The Commission should approve the exceedance approach because it is the only method that accurately and reliably reflects the capacity contribution of wind and solar resources during the Company's system peak. It is also consistent with PURPA which provides that rates paid to QFs for energy and capacity be equal to the incremental energy and capacity cost the utility would have incurred but for the purchase from the QF.

The Commission should reject the Effective Load Carrying Capability ("ELCC"), Capacity Factor Method ("CFAM"), Equivalent Conventional Power ("ECP") and other similar methods mentioned in the NREL report and advanced by other parties in this case because they do not measure the capacity contribution or reliability of intermittent resources during the Company's coincident peak. Tr. 38, ll. 12-15. Instead, they measure what the Company avoids during all other hours of the year, or average energy, and are therefore not appropriate for determining capacity contribution for QF pricing. Duvall Rebuttal/6, ll. 129-130. NREL made it clear in the report that the results were not appropriate for measuring the ELCC or ECP at the individual utility level. Duvall Rebuttal/7, ll. 152-153.

Under the OCS's and DPU's proposals, a QF wind resource would be unavailable to meet system coincident peak load 59 percent and 37 percent of the time, respectively. Duvall Sur-rebuttal/9, ll. 182-184. With respect to a QF solar resource, a comparison of the timing of solar output with the timing of the Company's peak load shows that the peak output of solar resources on the Company's system does not occur at the same time as the Company's peak load. Duvall Sur-rebuttal/12, ll. 227-228. Solar resources are not able to displace a CCCT based on the non-coincident peak output of the solar resources. Duvall Sur-rebuttal/12, ll. 233-234. In contrast, the Company's method for calculating capacity contribution takes these timing differences into account. Duvall Sur-rebuttal/13, ll. 235-236. From a practical standpoint, if the Commission were to adopt the ELCC, ECP, CFAM or other similar method advanced by other parties, the reliability of the system to meet coincident peak load would degrade. Duvall Sur-rebuttal/9, ll. 184-185. To avoid this degradation, the Company would be forced to acquire additional capacity to make up for any peak-load capacity that could not be served by the QFs, paying twice for the same capacity, contrary to PURPA and the ratepayer indifference standard. Duvall Sur-rebuttal/10, ll. 201-202. Although parties claim the Company ignores QF capacity value to the Company's system, the differential GRID studies used in the Proxy/PDDRR methodology already reflect the energy contribution and assign an avoided cost value to the QF for every hour of the year. Tr. 38, ll. 21-25. Thus, the Commission should adopt the Company's exceedance approach because it is based on the likelihood that a resource will be available to satisfy system coincident peak loads which is the essence of "capacity contribution." Duvall Rebuttal/6, 131-134.

2. It Would Be Contrary to PURPA's Ratepayer Indifference Standard to Approve Capacity Payments to QFs Before They Actually Defer a Resource Because QFs Would Receive Payments for Costs the Company Has Not Incurred.

The Commission should reject UCE's recommendation to change the timing of capacity payments for QFs currently in effect under the Proxy/PDDRR method. UCE provides no basis or evidence to support its recommendation for making capacity payments to QFs based on the next deferrable resource beginning in year one of their contract even though the Company is not planning to acquire the next deferrable resource under the 2013 IRP, a CCCT, until 2024. Duvall Rebuttal/9, ll. 210. UCE does not demonstrate how a capacity payment might be calculated under these circumstances and also fails to state what the amount of its proposed capacity payments in 2014 (year one) through year 2023 should be.

Notably, the Proxy/PDDRR method already recognizes the capacity deferral of front office transactions ("FOT") each year prior to the year of the next deferrable CCCT and includes this value in the energy portion of avoided costs pricing.[9] Duvall Rebuttal/10, ll. 212-214; Falkenberg Rebuttal/3, ll. 63-72; Abdulle Sur-rebuttal/6, ll. 109-113. UCE's claim that it does not necessarily agree the Proxy/PDDRR method compensates QFs for capacity during the resource sufficiency period because "market prices for front office transactions may merely reflect normal market forces of supply and demand" is unfounded. Wright Sur-rebuttal/11, ll. 236-237. UCE relies on testimony advanced by Phil Hayet in Docket No. 03-035-14 for this claim; however, UCE omits the part of his testimony that makes it clear Mr. Hayet was testifying about energy and capacity payments during the deficiency period, not the sufficiency period.[10] In fact, later in his testimony, Mr. Hayet recommended that the capacity payment be timed to match the year that the resource comes on line.[11] Finally, approving a capacity payment prior to the deferral of a CCCT in 2024 would produce pricing that is higher than avoided costs and would be contrary to the ratepayer indifference standard under PURPA.

3. <u>It Is Reasonable to Include Wind and Solar Integration Costs In the Calculation of Avoided Costs Pricing Because the Company Incurs Costs to Integrate Intermittent Resources</u>.

The Commission should approve the Company's proposed wind and solar integration costs in the Proxy/PDDRR calculations because the Company incurs costs to integrate wind and solar resources. Contrary to UCE's testimony, it is not reasonable to assume the Company does

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[9] See Rocky Mountain Power's Quarterly Compliance Filing – 2012. Q4 Avoided Cost Input Changes in Docket No. 03-035-14, December 28, 2012, Appendix B, Table 1, FN (2).

[10] Prefiled Direct Testimony of Phil Hayet for the Committee of Consumer Services, Docket No. 03-035-14, April 12, 2004, p. 10, ll. 15-17.

[11] *Id.*, at 13. (in response to the question "what is the Committee's avoided capacity cost recommendation for the long run period", Mr. Hayet responds "[s]pecifically, the generation unit planned to be added in a future year, as determined in PacifiCorp's latest IRP, should be the proxy unit for establishing that year's avoided capacity cost.")

not incur any costs to integrate solar resources. Duvall Rebuttal/14, ll. 282-284. In addition, even though the Company's system includes a minimal level of solar resources, the solar integration costs included in the avoided cost calculations are proportional to the output of the solar facilities. If a solar resource is a small facility it will pay less integration costs on a total dollar basis than if it were a large facility. Duvall Rebuttal/15, ll. 288-291. Contrary to the DPU's testimony that solar integration costs should be lower than the Company's wind integration costs since solar energy is less variable and more predictable than wind energy, the costs of reserves necessary to integrate solar could be equal to or greater than wind integration. Duvall Rebuttal/15, ll. 296-297.

4. PURPA Prohibits Fuel, GHG and Climate Change Risk Adders to the Calculation of Avoided Costs Because the Company Does Not Incur Those Costs.

The Commission should reject parties' recommendations to include any fuel, GHG and climate change adders to the calculation of avoided costs because it would be contrary to PURPA's ratepayer indifference standard. Under PURPA, the Company is required to purchase energy offered by QFs at rates that are just and reasonable to customers and that are no greater than the incremental cost the Company would otherwise incur to generate the energy itself or purchase it from another party.[12] UCE requests that the Commission account for what it characterizes as "real, avoidable costs" in its avoided costs rates for renewable QFs. Wright Sur-rebuttal/16, ll. 345-346. UCE bases its recommendation, in part, on a FERC decision involving a challenge brought by three California utilities to a feed-in tariff program for combined heat and power ("CHP") projects adopted by the California Public Utilities Commission ("CPUC") to implement a California statute intended to promote CHP development.[13] In sur-rebuttal

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[12] Pub L. No. 95-617, 92 Stat. 3117 (1978).

[13] California Pub. Utilities Comm'n S. California Edison Co. Pac. Gas & Elec. Co. San Diego Gas & Elec. Co., 133 FERC ¶

testimony, UCE quoted language from the FERC decision but omitted key language in the case. FERC, quoting another case, indicated that "if the environmental costs are 'real costs that would be incurred by utilities,' then they "may be accounted for in a determination of avoided cost rates."[14] In addition, as noted by counsel for OCS at hearing, UCE omitted additional language from that FERC decision as follows, "We also note that, although a state may not include a bonus or adder in the avoided cost rate unless it reflects actual costs avoided, 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." Tr. 243, ll. 5-10.

The Commission should also reject any comparison of the Company's forecast fuel costs to speculative and uncertain costs related to any type of risk adder. Although it is true that fuel costs in the distant future are not known today, they can be and are forecast by third-party sources such as PIRA or Cambridge Energy. Tr. 36, ll. 2-3. The Company knows with certainty that it will incur fuel costs. And while the Company projects the potential cost of carbon regulation in its IRP process, it is not known at this time whether the Company will actually incur carbon costs. Tr. 36, ll. 14-16.

In conclusion, UCE and other parties are asking this Commission to include speculative and unsupported externalities that do not reflect the Company's avoided costs. This is impermissible under PURPA. The Commission cannot simply tack on a cost adder to reflect externalities with no additional showing of costs avoided by the Company. For these reasons, the Commission must reject UCE's and other parties' recommendation to include "avoidable" risks such as fuel, GHG and climate changes adders to the avoided cost calculation.

61,059 (2010)

[14] 133 FERC ¶ 61,059 (2010) (quoting SoCal Edison, 71 FERC ¶ 61,269 at 62,080).

C. It Would Be Good Policy for RECs Created from the Energy the Company Is Obligated to Purchase from QFs to Be Owned by the Company for the Benefit of Its Customers.

The Commission should grant ownership of RECs created from the energy the Company is obligated to purchase from QFs to the Company for the benefit of its customers for several reasons. First, PURPA requires utilities to purchase energy from a renewable QF solely because the energy produced from this type of QF is renewable. Tr. 112, ll. 7-10. The REC represents the renewable attribute created from the obligation to purchase that type of energy. Therefore, it is reasonable that the Company should also own the characteristic or attribute, i.e., the REC, that identifies the energy as renewable. Tr. 112, ll. 13-19. Second, the RECs can be used by the Company to meet the state's RPS target under Utah Code Ann. § 54-17-602. If an RPS requirement is ever passed in Utah, and assuming the Commission grants ownership of RECs to the Company and its customers, the Company could use the RECs to meet such RPS requirement, like utilities already do in California. Third, in the event RECs are not required for RPS compliance but are sold, all revenues from REC sales made by the Company are passed back to customers.

Since RECs are a creation of state law, this Commission has the authority to determine who owns the RECs in the initial instance. Tr. 111, ll. 13-16; *American Ref-Fuel Co.,* 105 FERC ¶ 61,004 (2003). Notably, this is the first time the Commission is being asked to make a policy decision on this issue in the absence of an existing contract. The Commission has not determined who owns a REC when it is created. Contrary to what parties in the case may claim, at this point, RECs created from the energy the Company is obligated to purchase from QFs cannot be claimed to be owned by anyone. Tr. 130, ll. 1-4.

While parties in the case may argue that the Commission's decision in *Cottonwood Hydro*[15] prohibits the Commission from making a policy decision here that is different from its decision in *Cottonwood Hyrdo*, the Company submits that their position is wrong. *Cottonwood Hydro* addressed the treatment of RECs specific to a particular contract between the Company and Cottonwood Hydro, LLC. Clements Rebuttal/5, ll. 88-89. In that case, parties asked the Commission to determine who could claim ownership of RECs where REC ownership was not specifically called out in the contract. Clements Rebuttal/5, ll. 91-92. The Commission determined that RECs under that contract did not automatically transfer to the Company. Clements Rebuttal/5, ll. 93-94. The Commission found that "absent a contract providing otherwise, the RECs remain with the QF even when the power generated is delivered to the utility."[16]

The statement of legislative policy under Utah Code Ann. § 54-12-1(2) is the state of Utah's recognition that PURPA imposes on utilities the obligation to purchase energy from renewable QFs, nothing more and nothing less. Tr. 149, ll. 24-25 and Tr. 150, ll. 1-8. The state of Utah, through this Commission, is advancing that policy objective by implementing the PURPA obligation on utilities at a state level. Any claim that the Commission must do anything else to advance this policy is unfounded and unsupported by any evidence on the record.

Based on the foregoing, the Commission is free to and should adopt the Company's proposal that large QF contracts include explicit contract terms and contract language stating that RECs from large QFs are owned by the utility and its customers. Clements Rebuttal/5, ll. 98-100.

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[15] *In the Matter of the Complaint of Cottonwood Hydro, LLC vs. Rocky Mountain Power,* Docket No. 10-035-15, Report and Order (May 27, 2010) ("Cottonwood Hydro").
[16] *Id.*, at 9.

D. Miscellaneous Issues

In testimony, KUC/Tesoro recommended that the Commission impose additional filing requirements on the Company under Schedule 38. At the hearing KUC/Tesoro appeared satisfied with the Company's commitment to provide information supporting avoided cost calculations, including assumptions made and studies used, upon request by the interested QF. KUC/Tesoro stated that "hopefully those issues have been pretty well taken care of". Tr. 222, ll. 15-17. Given KUC/Tesoro's testimony at the hearing, the Company submits that the issue has been resolved, and that no further determination from the Commission on this issue is necessary.

During the hearing, a question was raised by the bench about the timing of the Commission's determination regarding the Company's planned IRP resources and identifying cost-effective resources for the purpose of avoided cost determination. Tr. 182, ll. 17-22. The Company notes that this issue was not addressed by any party in this proceeding with any degree of specificity. Thus there is no evidence on the record to support any changes to the current process. In addition, the Company notes that it already accounts for changes in the IRP in avoided cost calculations through the Company's updates to Schedule 38, filed with the Commission on a quarterly basis. The updates are reviewed, and either recommended for approval or rejection, by the DPU. Tr. 187 and 188, ll. 19-25 and ll. 1-13, respectively. Therefore, the Company recommends that the Commission continue to rely on the quarterly updates to monitor and evaluate appropriate avoided costs calculations.

III. CONCLUSION

Based on the foregoing, the Company recommends that the Commission discontinue the currently-effective Market Proxy methodology for wind QFs in favor of the modified Proxy/PDDRR method described above and change the way the capacity contribution portion of the avoided cost payment is calculated consistent with the Company's exceedance approach. The Company submits that no compelling evidence has been provided by any party to support a change to the timing of capacity contribution payments and, consistent with federal and Utah laws, that the Commission should continue to link the timing of capacity contribution payments with the timing of when the next deferrable resource would actually be deferred. Integration costs should be included in the calculation of avoided cost prices for wind and solar resources because both are intermittent and cause the Company to incur such costs. In addition, the Commission should reject parties' recommendations to include fuel, GHG and climate change adders to avoided costs because they are both unsubstantiated and not permitted under current federal and Utah laws. Finally, it is good policy for RECs created from the energy the Company is obligated to purchase from QFs to be owned by the Company for the benefit of its customers.

DATED this 27th day of June, 2013.

Respectfully submitted,

ROCKY MOUNTAIN POWER

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Mark C. Moench
Yvonne R. Hogle

Attorneys for Rocky Mountain Power