BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	)	
Rocky Mountain Power for Approval	)	Docket No. 12-035-100
of Changes to Renewable Avoided Cost	)	
Methodology for Qualifying Facilities	)	DPU EXHIBIT 2.0
Projects Larger than Three Megawatts	)	

Direct Testimony of

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Division of Public Utilities

March 29, 2013

Q. Please state your name, business address, and employment for the record.

A. My name is Dr. Abdinasir M. Abdulle; my business address is 160 E. 300 South, Salt Lake City, Utah 84114; I am employed by the Utah Division of Public Utilities ("Division").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Division.

Q. Would you summarize your education background for the record?

A. I have a Ph.D. in Economics from Utah State University. I have been employed by the Division for about 12 years.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Division's response to certain issues raised by Mr. Greg Duvall and Mr. Paul Clements of Rocky Mountain Power ("Company") in their direct testimonies in support of the Company's application for approval of changes to renewable avoided cost methodology for qualifying facilities larger than three megawatts.

Q. What specific action did the Company request the Commission to take in that application?

A. In its application dated October 9, 2012 in Docket No. 12-035-100, the Company requested re-examination of the Avoided Cost methodology pertaining to renewable qualifying facilities larger than three megawatts adopted by the Commission in its

October 30, 2005 Order in Docket No. 03-035-14. In its application, the Company listed the specific items for which it is seeking re-examination. These specific items are reproduced here for ease of reference for the reader:

a. Whether the Market Proxy method continues to produce avoided costs that are in the public interest, including

   i. the definition of the IRP target;

   ii. the timing of the need for renewable resources; and

   iii. the treatment of resources acquired for RPS compliance.

b. What the proper implementation of PDDRR for renewable QF resources is, including

   i. the capacity contribution of intermittent resources;

   ii. the type of resources deferred (thermal or renewable); and

   iii. integration costs.

c. What the ownership of renewable energy attributes ("RECs") from renewable QF resources is, including

   i. the ownership of RECs under the Proxy/PDDRR method; and

   ii. the right of a QF to buy-back RECs and the associated price.[1]

[1] In the Matter of 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, Company Application. p. 5.

<u>RESPONSE TO MR. GREGORY DUVALL</u>

Q. What aspects of the Company's application did Mr. Duvall's testimony cover?

A. Mr. Duvall provided testimony in support of parts a and b of the above list of items in the Company's application.

Q. How does Mr. Duvall propose the avoided cost for renewable QFs exceeding three megawatts should be calculated?

A. Mr. Duvall proposes that the avoided cost for all renewable QFs exceeding three megawatts should be calculated using the Proxy/PDDRR method with updated capacity and integration costs.[2] The Market Proxy method would no longer be used.

Q. How did Mr. Duvall justify the abandonment of the Market Proxy method?

A. Mr. Duvall justified his proposal on the basis that the Market Proxy method no longer produces avoided costs that are in the public interest. He argues that it does not account for the proper definition of the IRP target, the timing of the need for new resources, and the cost-effectiveness of the IRP wind resources.

Q. What is the Division's position regarding the Company's proposed abandonment of the Market Proxy method for calculating avoided costs for renewable resources greater than three megawatts?

[2] In the Matter of 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, Mr. Duvall's Direct Testimony, pp. 3-4.

A. The Division agrees with the Company that under the current circumstances the Market Proxy method does not produce accurate avoided cost prices. Furthermore, the Division believes that the Market Proxy method is significantly flawed and should not be reintroduced in the future. The adoption of the Market Proxy method was justified on the basis of accuracy, simplicity, and transparency. In its Order in Docket No. 03-035-14, the Commission indicated:

> … Further, we accept the market proxy as it is reasonably accurate but also simple and transparent.[3]

At the time of this determination, the most recent IRP was that of 2004 which included 1,400 MW of cost-effective wind resources. The Company set this 1,400 MW as the target of the amount of wind resources to be acquired in the coming few years. Consequently, the Company regularly issued RFPs to acquire cost effective wind resources. It was anticipated that the Company would regularly acquire wind resources for the foreseeable future.

Although the Division disagrees, under those circumstances it was assumed that the latest acquisition was reasonably close to the actual avoided energy and capacity costs of a wind QF. The Division disagrees with this assumption in that the new QF resource that is to be introduced into the system would displace the next highest cost resource in the stack of resources after the highest cost resource was displaced by the previously acquired QF resource.

[3] 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, Order dated October 31, 2005, p. 21.

Furthermore, in the 2011 IRP, Docket No. 11-2035-01, the Company indicated that it had met its IRP target and the 2011 IRP did not include cost effective wind resources in the preferred portfolio. Consequently, the Company is not seeking any new wind resources. Based on information to date, it is anticipated that the only wind resources in the 2013 IRP preferred portfolio will be those necessary to meet various renewable portfolio standards required in some of the Company's other state jurisdictions.

Given that the IRP target has been satisfied and no new cost effective target is anticipated in the current IRP, and that the Company is not seeking new wind resources, can the Market Proxy method produce the accurate avoided costs as was previously assumed?

The Division answers no to this important question. The wind target has been met and is not currently part of the IRP. The only wind resources in the current IRP are those designed to meet state policy mandates and do not satisfy the least cost/least risk portfolio choice supported by the Commission's past orders and IRP guidelines.

Q: Would you elaborate?

A: Yes. In its Order on Request for Agency Action in Docket No. 12-2557-01, the Commission indicated that

> …as long as wind resources are present in the IRP, RMP should use the market price proxy method to determine indicative avoided cost pricing for wind QFs. This is the plain meaning of Ordering Paragraph 6, quoted above.[4]

[4] In the Matter of Blue Mountain Power Partners, LLC's Request that Public Service Commission of Utah Require PacifiCorp to Provide the Approval Price for Wind Power for the Blue Mountain Project. Docket No. 12-2557-01, Order dated September 20, 2012, p. 10.

The Division interprets the phrase “as long as wind resources are present in the IRP” in the above quoted Commission order as referring to only cost effective wind resources in the IRP. In other words, those resources that meet the Commission’s directed criteria of least cost/least risk.

Additionally, considerations of the non-cost effective wind resources in the IRP would violate Section 210 of the Public Utility Regulatory Policies Act of 1978 (“PURPA”) in that it clearly will not result in rate payer indifference.

The wind resources in the 2011 IRP which were included to meet RPS policies required by other states are not and were not selected as necessary, cost-effective resources to meet load. Therefore, they were not part of the least cost/least risk portfolio for Utah ratepayers and should not be interpreted as such in an avoided cost calculation.

Chapter 5, Portfolio Development, of the 2011 IRP states:

> PacifiCorp used the System Optimizer capacity expansion optimization model to develop resource portfolios based on inputs and assumptions updated throughout the business planning process. For this portfolio development, the Company devised wind resource acquisition targets outside of the portfolio modeling effort, and treated these targets as a fixed resource schedule in the capacity expansion modeling.[5]

Since these wind resources were imposed on the model regardless of whether they are cost-effective or not, they could not be considered as part of the resources selected in an attempt to minimize cost and risk. Finally, in his direct testimony, Mr. Duvall stated that:

[5] PacifiCorp’s 2011 Integrated Resource Plan Update, Docket No. 11-2035-01, p. 44.

> The volume of wind additions included in the 2011 IRP Update was determined based on the Company's compliance obligation in Oregon, Washington, and California assuming all of the cost, benefits and RECs were assigned to these three states.[6]

As an aside, the Division notes that this statement is inconsistent with the 2010 Protocol regarding the allocation of portfolio standard resource costs. The 2010 Protocol states:

> Costs associated with resources acquired pursuant to a State Portfolio Standard, which exceeds the costs PacifiCorp would have otherwise incurred, will be assigned on a situs basis to the State adopting the standard.[7]

However, the Division believes that this issue would be better addressed in a different forum.

In conclusion, the Division believes that under the current circumstances where no cost effective wind resource is included in the IRP and that the price of the most recently acquired wind resource is outdated, the Market Proxy method is not a valid method to calculate the Company's avoided costs.

As previously mentioned, the Division believes in any case that the Market Proxy method is a very poor method for calculating avoided costs.

Q. Can you explain why the Division believes the Market Proxy is a poor method for calculating avoided costs?

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[6] In the Matter of 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, Mr. Duvall's Direct Testimony, pp. 12-13.

[7] In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues, Docket No. 02-035-04, Mr. Duvall's Direct Testimony, pp. 12-13.

A. Yes. The IRP process is intended to produce the least cost/least risk portfolio of resources for the utility to provide reliable and safe services. As resources are added to the portfolio mix, all resources undergo dispatch changes. In other words, rather than being static, the IRP process or evaluation of resources is inherently dynamic and affected by the addition of alternative resources. Calculations of the avoided costs should be consistent with the dynamic nature of the IRP portfolio selection process to maintain a least cost combination of resources.

In contrast, the Market Proxy methodology assumes that the portfolio selection is static—as alternative resources are added to the mix, the Market Proxy method assumes all other resources are unaffected.

Q: Would you explain how the Market Proxy assumes the portfolio selection is static?

A: Yes. The avoided cost of an alternative resource is the difference in revenue requirement between two least cost/least risk portfolios, one with and one without the alternative resource under consideration.

Generally, when a QF is introduced into the portfolio mix, it displaces the highest cost resource in the resource stack. The next QF introduced displaces the next highest cost resource because the highest cost resource already has been displaced by the first QF. Each successive QF, in other words, displaces an existing resource of lesser cost than the previous QF.

Instead of this logical sequential displacement process, the Market Proxy method assumes that the current wind QF displaces the same resource that the previous wind QF has already displaced. In other words, allowing for differences in operating characteristics, the Market Proxy method assumes the avoided costs of the two wind QFs are identical. Since the two QFs cannot displace the same resource, the Market Proxy method is clearly inconsistent with the concept of avoided cost and with the PURPA indifference standard, and with the dynamic nature of the IRP process.

Q: Do you have any other comments on the Market Proxy method?

A: Yes. The Market Proxy method is similar to the proxy plant method described by the Tellus Institute in its handbook on avoided costs.[8]

According to the Tellus Institute, the proxy plant method will yield accurate results only if the following two conditions are met:

1. "[T]he operating characteristics . . . of the proxy plant closely match those of the alternative resource under consideration; and
2. "[T]he alternative resource exactly replaces the entire capacity and energy provided by the proxy plant in a least-cost plan and does not significantly affect any other plant additions or operations." (Section II-7)

However, even if these two conditions could be met, the proxy plant (and the Market Proxy) suffers a number of limitations.

First, by adding an alternative resource in the mix, you will be avoiding the construction or operation of pieces of a number of different types of resources in different time

[8] Tellus Institute Resource and Environmental Strategies. 1995. Costing Energy Resources Options: An Avoided Cost Handbook for Electric Utilities. Section II-7.

periods and not the cost of a single generating unit as assumed by the proxy method. (Section II-9)

Second, if the operating characteristics of the alternative resource differ from that of the proxy, then the components of the avoided cost will be different than the components of the avoided cost of the alternative resource.

Third, differences in the size of the alternative and the proxy resources will lead to an over or under estimation of the total avoided cost. If the alternative resource is smaller than the proxy resource, the proxy will never be completely avoided resulting in higher avoided capacity cost. If the alternative is larger than the proxy, then it is avoiding more than it is credited for, resulting in lower total avoided cost.[9]

As the Tellus Institute explains,

> The operating costs and characteristics associated with a *single* type of generating unit cannot typically represent those associated with the complex *set* of avoided power plants (and plant operations) that actually result when an alternative resource is added to a utility system. (Section II-9; emphasis in the original)

Because of these reasons and limitations, the Division believes that the Market Proxy method is significantly flawed and should not be used under the current circumstances or reintroduced in the future.

[9] Id. pp. Section II 8 – 9.

Q. How do you propose to calculate the avoided costs of wind resources in excess of the IRP target limit?

A. I propose that the Proxy/PDDRR method—the next deferrable resource (Proxy) is used to calculate the avoided capacity cost and PDDRR method is used to calculate the avoided energy cost—be used to calculate the avoided costs of wind resources exceeding the IRP target limit. This is in line with the Commission's 2005 Order. However, the 2005 Order indicated that both the capacity cost and the integration cost need to be updated as more information becomes available. Therefore, the Division agrees with the Company that the Proxy/PDDRR method be updated for both the capacity contribution and the integration cost.

Q. What update to the capacity contribution did the Company propose?

A. The Company proposed that an average aggregate capacity based on the 100 peak load hours in each of five years, 2007-2011, during the summer months (June through September) should be used. This average aggregate capacity factor will be equaled or exceeded in 90 percent of the top 100 summer load hours.

Q. How did the Company calculate this aggregate capacity factor?

A. Using historical data from 2007 to 2011, for each of wind, solar peak, and solar energy generation types, the Company calculated the capacity factor associated with each hour of the year by dividing each hour's aggregate energy output for a year by each hour's aggregate nameplate capacity for that year. These aggregate capacity factors were then matched with the top 100 summer load hours for each year. Then the aggregate capacity factor that equaled or exceeded 90 percent of the top 100 summer load hours in each is picked. The average of these annual aggregate capacity factors was then calculated to arrive at the average capacity contribution of wind and solar resources.

The 90 percent level was chosen because it is assumed that the next deferrable resource in the IRP will be available 90 percent of the peak load hours. Hence, the level of power provided by the intermittent resource that corresponds to the average aggregate capacity factor would meet the 90 percent reliability requirement. The Company calculated the capacity contribution as 4.1 percent for wind, 11.5 percent for energy-oriented solar facility, and 25.9 for peak-oriented solar facilities.

Q. What is the position of the Division regarding the Company's proposed update of the capacity contribution?

A. The Division does not oppose the Company's proposed update to the capacity contribution. However, because the circumstances under which the Company is operating are not always the same from one time period to the next, the Division recommends that the capacity contribution needs to be updated periodically, probably at least annually.

Q. What update to the integration cost did the Company propose?

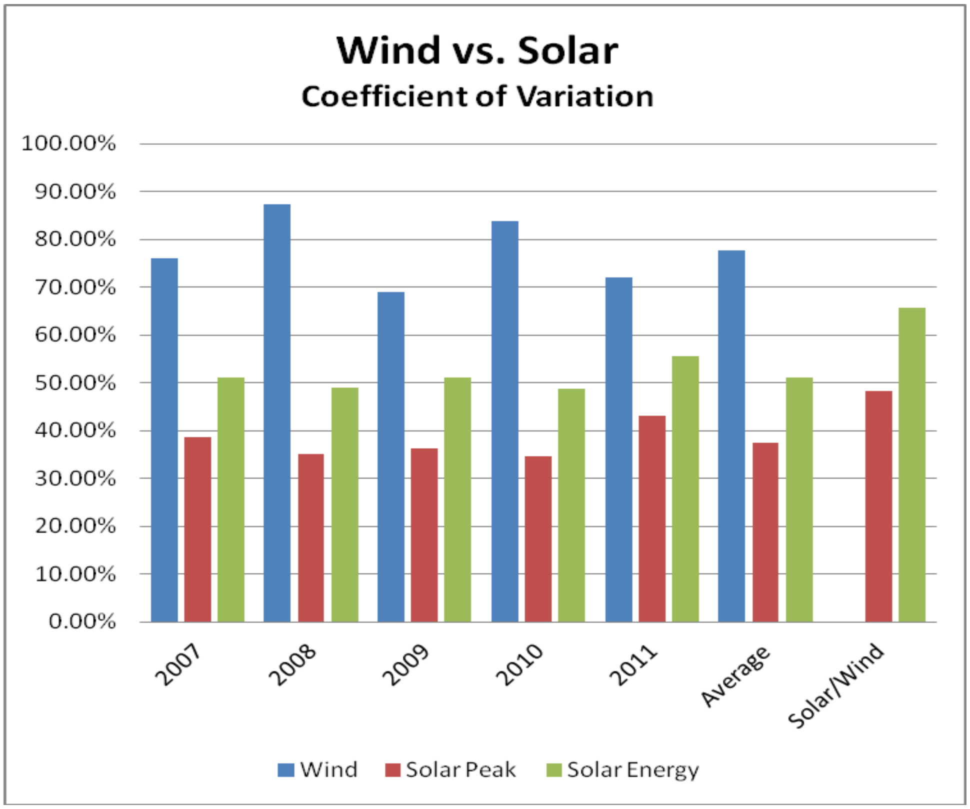
A. The Company proposed to use of the same method currently used in the IRP and the general rate case to determine the integration costs of the intermittent resources. Under this method the Company calculated a wind integration cost of $4.35 per megawatt hour on a 20 year nominal levelized basis beginning 2013. Furthermore, the Company proposed that this wind integration cost also be used as a proxy for integrating solar.

Q. Did the Company conduct any analysis to justify that the solar integration cost could be approximated by the wind integration cost?

A. No. In its response to the DPU's Data Request 2.1, in which the Division asked the Company to explain in detail why the wind integration costs are a reasonable proxy for solar given the nature of solar energy is likely to be more regular and predictable than wind energy, the Company answered that it did not perform a study to determine whether solar energy is more regular and predictable than wind and, therefore, the Company does not necessarily agree with the premise of the question.

Q. Does the Division believe that wind integration costs could be used as a reasonable proxy of solar integration costs?

A. No. The Division performed some analysis, using Company provided data, to determine whether or not wind energy is more regular and predictable than solar energy. The results are shown in the following graph.



The graph shows the coefficient of variations[10] of the loads for wind, peak-oriented solar facilities, and energy-oriented solar facilities for the five years, 2007 to 2011, and the average for the five years. The last two bars of the graph show that the peak-oriented solar facilities are only 48.36 percent as variable as wind facilities on a relative basis; likewise, energy-oriented solar facilities are only 65.79 percent as variable as wind on a relative basis. Based upon the data the Company has made available, solar energy appears to be more regular and predictable than wind energy.

Intuitively, this makes sense, since the sun rises in the east and sets in the west—each day, 365 days a year—in a highly predictable pattern.

[10] The coefficient of variation is the ratio of the standard deviation to the mean. It is used to compare the degree of variation between two or more data series.

Q. What is the Division's proposal for the integration cost of solar?

A. Based on the results above, the Division proposes that peak-oriented solar resources be charged about 50 percent of the wind integration cost ($2.18) and the energy-oriented solar be charged about 65% of the wind integration cost ($2.83).

<u>RESPONSE TO MR. PAUL CLEMENTS</u>

Q. For which aspects of the Company's application did Mr. Paul Clements provide testimony?

A. Mr. Clements provided testimony in support of part c of the above list of items in the Company's application, namely, the ownership of RECs.

Q. What did Mr. Clements propose regarding the ownership of the RECs?

A. Mr. Clements proposes that the RECs should be owned by the Company under any power purchase agreement executed under Schedule 38.

Q. How did Mr. Clements justify his proposal?

A. Mr. Clements argues that the utility is made to purchase power from qualifying facilities because of the environmental attributes of that power. Therefore, the RECs are part of services or commodities the Company is buying with payments of avoided costs. Further, Mr. Clements argues that if the Company is made to pay for the RECs separately, it would amount to the Company and its customers paying for the RECs twice: first when the Company pays for the power purchased from the QF and then second when it pays for a separate purchase of the RECs.

Q. Would you comment on Mr. Clement's claim that RECs are part of what the Company is buying with the payment of avoided costs?

A. Yes. Section 210 of the Public Utilities Regulatory Policies Act (PURPA) of 1978 specifies the obligation of the Company to purchase capacity and energy made available from a QF, and to make such purchases at no more than avoided cost. Renewable generators produce and sell two different products: generic power, traded in the power market, and RECs, traded in a separate market. Note that the obligation to purchase the power, although based on the attributes of the QF, was established under PURPA long before the market for RECs was established.

PURPA contemplates the purchase of the generic power, not the RECs. Hence, the RECs are not part of what the Company buys with the payment of avoided cost.

Q: Does the avoided cost methodology proposed by the Company compensate the QFs for RECs?

A: No. Avoided costs are designed to compensate for the energy and capacity generated by a QF at the purchasing utility's avoided costs of generating or purchasing an equivalent amount of energy and capacity. It does not include the RECs.

Section 210(b) of PURPA provides for the pricing of QF power at the purchasing utility's avoided cost. Thus QFs are paid for energy and capacity produced by their facilities based on the purchasing utility's costs of power from any alternative power source, not on the environmental attributes of the selling QF.

Furthermore, once a utility's avoided costs are determined, the same power purchase price applies to all QFs, be they a renewable energy resource or a fossil fuel-fired co-generator.

Therefore, the Company's avoided cost methodology does not compensate QFs for RECs associated with renewable generation.

Q: You said that the same power purchase price applies to all QFs. Can you elaborate?

A: Conveyance of RECs under PURPA contracts based solely on avoided cost would effectively discriminate among different types of QFs, in violation of section 210(b)2 of PURPA. A QF may be either a qualifying cogeneration facility or a qualifying small power production facility. Only qualifying small power production facilities using renewable energy resources could be allocated RECs. Qualifying cogeneration facilities operating on fossil fuels are typically not eligible for RECs under any state RPS program.

If RECs were conveyed to the purchasing utility solely in exchange for avoided cost, the avoided cost would effectively vary based on whether the utility was buying from renewable energy small power QF or a fossil fuel-fired cogeneration QF, because the cost of power to utilities buying from small power QFs would be reduced by the value of the RECs that the utilities receive.

However, both small power and cogeneration QFs provide the same generic energy and power product at the same utility avoided cost. Applying the same power purchase to these two types of QFs is, therefore, discriminating against the small renewable power production facilities. This is inconsistent with the framework created under section 210 of PURPA, which requires, among other things that rates for purchase of QF power "shall not discriminate against qualifying co-generators or qualifying small production."

Q. Did the Commission address the issue of REC ownership in its 2005 Order?

A. Yes. During the 2005 docket, the most recent IRP was that of 2004. In the 2004 IRP a value of $5.00 per megawatt hour was attributed to the RECs and was included as a credit in the evaluation of wind versus other supply-side resources. Hence, the Commission ruled that:

> PacifiCorp paid for the RECs and therefore owns the RECs and the price includes the value of RECs.[11]

Q. Are there any other Commission rulings regarding REC ownership?

A. Yes. In Cottonwood Hydro, LLC vs. Rocky Mountain Power case in Docket No. 10-035-15, the Commission stated:

> Unless provided for otherwise in a contract, the RECs remain with the generator of renewable energy, and may be sold and valued separately from the energy produced or retained by the generator of the RECs.[12]

Q. What is the Division's position regarding the ownership of RECs?

A. The Division's position is that if the Company pays for the RECs, than the RECs should be owned by the Company. Otherwise, the RECs remain with the developer.

[11] Docket No. 03-035-14. In the Matter of the Application of PacifiCorp for Approval of an IRP-Based Avoided Cost Methodology For QF Projects Larger Than One Megawatt, Report and Order dated October 31, 2005, p. 25
[12] Docket No. 10-035-15, In the Matter of the Complaint of Cottonwood Hydro, LLC vs. Rocky Mountain Power, Report and Order dated May 27, 2010, p. 11.

As proposed by the Company, the Division does not believe that the PDDRR method explicitly compensates the developer of a renewable QF for the RECs,

Q. What is the Division's position regarding whether the developer should be given the right to buy back the RECs from the Company?

A. The answer depends on what method the Commission adopts for renewable QFs. In general, the Division believes that there is a market for the RECs and the owner of the RECs should have the discretion to sell, or not to sell, to whomever it wants.

In any specific case where the Company purchases the RECs from the developer, the developer should be required to pay the price reflected in the avoided cost payment. For example, if the Commission decides to adopt the Market Proxy (or similar) method for wind QFs, and that Market Proxy includes a value for RECs, then, at a minimum, the developer should repurchase the RECs at the value embedded in the Market Proxy price.

This is the only price that meets the PURPA principle of ratepayer indifference.

Q. Are there any other issues that you wish to comment on?

A. Yes. In running its GRID model for this docket, the Company did not include in the stack of potential resources the 2 MW solar facility recently acquired in Oregon as a state mandated situs plant for interstate allocation purposes, nor the prospective wind facilities that the Company believes it will need to satisfy state RPS requirements in the latter part of this decade as included in its latest IRP. If the Company had included these plants in its GRID modeling, the dispatch results and consequently the avoided cost calculations would have been somewhat different. At this time the Division does not have an opinion regarding the proper treatment of these types of resources in avoided cost calculations in Utah, or in other applications of GRID. The Division recommends that the Commission open a separate docket wherein technical conferences and other investigations by the Commission may determine what would be the proper treatment of these types of resources.

Q. Does that conclude your direct testimony?

A. Yes.