- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

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 ON RECONSIDERATION AND CLARIFICATION

ISSUED: February 2, 2006

By The Commission:

INTRODUCTION AND PROCEDURAL BACKGROUND

On October 31, 2005, the Utah Public Service Commission ("Commission") issued its Report and Order ("October 2005 Order" or "Order") approving methods for calculating avoided generation costs for cogeneration Qualifying Facilities (QF) greater than one megawatt and small power production QFs greater than three megawatts. Avoided costs are costs PacifiCorp ("Company") would incur to serve its native load "but for" the generation provided by the QF. The Order directs parties to convene a workgroup and provide a case-by-case method to calculate avoided transmission costs and losses within 21 days of the Order.

Pursuant to the October 2005 Order, on November 21, 2005, the Utah Division of Public Utilities ("Division") filed the QF Transmission Task Force Report. The report states the parties were unable to agree upon a method to determine avoided transmission capacity costs and losses. The report consists of a summary matrix of the task force participants' positions, appended by the individual statements of most parties. The Company, Division, Committee of Consumer Services ("Committee"), Mountain West Consulting LLC ("Mountain West") Wasatch Wind LLC ("Wasatch Wind"), US Magnesium LLC together with Pioneer Ridge LLC

("US Mag/Pioneer"), each provide a position statement. The positions of these parties plus those of ExxonMobil and Tesoro are summarized in the matrix. All except Tesoro are parties in this docket.

On November 30, 2005 four parties submitted filings with the Commission. Wasatch Wind filed its Request for Clarification and Petition for Reconsideration of Order. The Committee filed its Request for Reconsideration. UAE Intervention Group ("UAE") filed its Petition for Review, Rehearing and Clarification. The Company filed its Petition for Rehearing or Reconsideration.

On December 12, 2005, Wasatch Wind filed its Response to Petitions for Rehearing and Clarification. On December 14, 2005, the Company filed its Response to UAE Intervention Group's Petition for Review, Rehearing and Clarification and Wasatch Wind's Request for Clarification and Petition for Reconsideration of Order. On December 15, 2005, Pioneer Ridge filed its Response to the Committee's Request for Reconsideration and PacifiCorp's Petition for Rehearing or Reconsideration. On December 16, 2005, Mountain West filed its Response to the Committee's Request for Reconsideration and PacifiCorp's Petition for Rehearing or Reconsideration.

On December 19, 2005, the Commission issued its order granting Reconsideration and Clarification and its Notice of Scheduling Conference. The scheduling

conference order stated the Commission would inform parties of the issues to be reconsidered or clarified and set a schedule for further proceeding in this docket.

Pursuant to notice, a scheduling conference was held on January 4, 2006. Commission staff attended to inform parties the Commission required additional testimony and hearing to determine the appropriate method for calculating avoided transmission capacity costs and losses and to reconsider Company requirements for providing access to its GRID computer model. GRID is the Company's hourly production cost computer simulation model. Specifically, the Commission will consider UAE's recommendations for access to the GRID model until it is made available by the Company on the internet. A scheduling order was issued January 10, 2006 setting the dates for filing testimony and hearing these two issues. Additionally, the Commission stated in the scheduling order it would provide parties with Commission questions on January 17, 2006 regarding the QF Transmission Task Force Report. Responses can be provided in direct testimony on the transmission issues. Remaining issues will be clarified or reconsidered using the existing record and addressed in this Order on Reconsideration and Clarification.

DISCUSSION, FINDINGS AND CONCLUSIONS

In addition to the avoided transmission cost issues and GRID access described above for which additional testimony and hearing is scheduled, Petitioners request clarification,

reconsideration, review or rehearing of issues generally categorized as follows and presented in the order in which the topic appears or would appear in our October 2005 Order: 1) Schedule Nos. 37 and 38 language; 2) "next deferrable resource" definition; 3) non-firm transmission modeling in GRID; 4) "dispatch" definition and pricing method for non-dispatch QF power in a

variable pricing option; 5) variable pricing index; 6) QF availability pricing adjustments; 7) relationship of the wind proxy method to Request For Proposal (RFP) requirements, the Public Utility Regulatory Policy Act (PURPA) and Federal Energy Regulatory Commission (FERC) rules for determining avoided costs and to the company benchmark resource; 8) QF wind profile adjustments in the wind proxy method; 9) wind integration costs; 10) renewable energy credits (RECs); 11) short-term capacity payments; 12) finality of the October 2005 Order.

Schedule Nos. 37 and 38 Language: Page 5 of the October 2005 Order generally repeats language contained in the current Schedule No. 38 that states "Additional or different requirements may apply to Utah QFs seeking to make sales to third-parties, or out-of-system QFs seeking to wheel power to Utah for sale to the Company." UAE requests confirmation or clarification that the pricing and other provisions of the October 2005 Order, as well as the requirements of Schedule No. 37, apply equally to any QF able to deliver power into Utah, regardless of where the QF is located. In opposing comments, the Company counters the PURPA utility purchase obligation does not extend throughout the state in which the utility is located and the issue is beyond the scope of this proceeding.

The methods approved in our October 2005 Order are to be used for indicative pricing for QFs eligible for Schedule No. 38. Schedule No. 38 is available to owners of QFs in all territory served by the Company in the State of Utah. The Order applies to QF power in the Company's Utah service territory regardless of how it gets into this service territory. Although the language referenced in Schedule No. 38 potentially limits application of Schedule No. 38 to particular QFs, to our knowledge it has been in the tariff for several years without comment or incident and was not discussed at all in this proceeding by any party. Since the language states

additional requirements *may* apply rather than *will* apply to such QFs, we provide no further clarification or make language changes at this time.

Next Deferrable Resource Definition: UAE requests clarification of how the next IRP deferrable resource is to be determined. UAE submits that QF pricing requests made prior to the Company's 2005 IRP update should be based on the 2009 gas plant proposed in the 2004 IRP. Going forward, to reduce ambiguity and provide QF pricing certainty, UAE requests the Commission specifically identify the next IRP deferrable resource when the Company requests IRP acknowledgment or files any IRP update. UAE recommends this next deferrable resource remain the resource used for QF pricing requests until a subsequent Commission order is issued explicitly changing the next deferrable IRP resource for QF pricing purposes, which would then be used for prospective QF pricing requests.

The Company opposes these recommendations arguing: UAE supported the use of the next deferrable IRP resource without raising any of these issues before; the docket is about

method not prices; the prices presented in the case are illustrative examples only; Company testimony made clear its intention to update GRID modeling and proxy pricing for consistency with its most recent IRP or IRP update; pricing without update would not be just and reasonable nor satisfy the ratepayer indifference standard.

Parties recommend in testimony the next deferrable resource be consistent with the most recent IRP or IRP update. No party argued in opposition to this definition and no party made it a point to propose a different definition. Additionally, the ratepayer indifference standard is not satisfied without update. Parties did request clarity on how changes to the GRID model or proxy would be communicated to regulatory authorities and other interested parties. We ordered all updates and changes be filed with the Commission and Division. To date the Commission has received no such changes by the Company, other than the IRP update, even though we have recently received QF contracts for approval with pricing substantially different from the illustrative pricing presented in this docket. However, we affirm our decision to require all model and proxy changes be filed with the Commission and Division and order the Company to promptly comply with this requirement. This approach provides timely adjustments to avoided cost calculations thereby balancing the principle of ratepayer neutrality with timely and transparent pricing information to QFs.

Non-Firm Transmission Modeling in GRID. UAE asks the Commission to direct the Company to promptly submit a filing demonstrating compliance with the Commission's Order directing the Company to include non-firm transmission in the GRID model based upon a 48-month history. UAE states the filing should specify the level of non-firm transmission included, provide support for the selected level, explain all changes made to the model and its inputs to incorporate non-firm transmission and explain any resulting impacts on the output of the model. In its

responsive comments, the Company argues the Commission's Order directing the Company to file notice of updates with the Commission and Division is adequate.

As we have yet to see such a notice of model changes, we agree with UAE that a compliance filing is necessary and so order as requested by UAE above.

Dispatch Definition and Non-Dispatch Method for Variable Pricing Option: UAE requests clarification that 1) variable prices (also referred to as tolling prices) be paid in all hours energy is dispatched by the utility on a day-ahead basis, and 2) the QF may deliver energy in non-dispatch hours at a price determined by an appropriate GRID run (or sell non-dispatch energy to others). The Company responds that these interpretations greatly expand the variable pricing option beyond that contemplated by the Company or beyond that presented to the Commission.

Since the Company makes hourly economic dispatch decisions and GRID simulates economic dispatch hourly, we conclude that limiting "dispatch hours" to day-ahead dispatch may be inconsistent with ensuring ratepayer neutrality. Therefore, we clarify that dispatch in variable pricing arrangements is not limited to day-ahead dispatch only. However, the Commission will consider the merits of contract specific language relative to dispatch on a case-by-case basis.

With respect to the second issue raised by UAE, we clarify the Partial Displacement, Differential Revenue Requirements (PDDRR) method approved for periods when the QF has the unilateral right to decide when the Company will purchase their power also applies to the non-dispatch deliveries of a QF electing the variable

pricing option. With respect to QF sales of power in non-dispatch hours to third parties, it is our understanding such wholesale sales are permitted under federal law and this is a federal issue.

Variable Pricing Index: UAE submits the Order's approval of the Company's relevant fuel costs in rates as the index for variable energy pricing is ambiguous, not properly supported on the record, and useless to QFs as a variable pricing option. UAE argues it is unclear what the index is, whether pricing is time-differentiated, and how it will be adjusted over the term of the contract. Therefore, UAE recommends, as it did in testimony and hearing, the Commission approve a market price index for tolling arrangements. The Company opposes this request arguing, as it did in testimony and hearing, that actual market pricing does not reflect the costs that are incurred by the Company and paid by ratepayers and therefore, avoided costs based on these indices will violate the ratepayer indifference standard.

We recognize the variable pricing proposal put forth by the Division, Company and Committee was made late in the process with limited supporting detail. However, we concur with these parties that in order to maintain ratepayer indifference, we must approve a fuel price index based on the utility's cost of fuel rather than its market value. Testimony states the Company's gas prices are a blend of contract prices and forecast market prices rather than 100% spot market prices. We affirm this decision.

We clarify our use of the term "relevant fuel costs in rates" and draw upon the existing record to explain the mechanics of the index. The Company, Division and

Committee all define the index for a variable price option as the fuel price allowed in rates by fuel type depending on deferrable plant. "Relevant fuel cost," therefore, simply means the fuel price allowed in rates that is consistent with the type of deferrable IRP plant used as the proxy plant for calculation of avoided capacity costs. Further, as generally recommended by the Division, this index shall be consistent with the most recent rate case fuel prices, be adjusted as new rates are set, and remain consistent with the fuel type of the IRP deferrable plant proxy that is the basis for the avoided capacity payments over the term of the QF contract.

As stated by the Division, this method promotes transparency because interested interveners can examine all of the Company's contracts and the forward market price curve used to establish rates and therefore to determine the variable price index. Whether this is an average price or a time-differentiated price shall depend upon the level of time differentiation in the modeling of net power costs in rates and we leave these details to contractual negotiation.

QF Availability Pricing Adjustments: UAE submits the Order's focus on price adjustments in the PDDRR method based upon differences in dispatchability, reliability and availability is clearly defensible. However, UAE requests clarification that the sentence, "For the QF to be paid for avoiding capacity, it must meet the availability of the avoidable resource" means "in a consistent manner to require the same availability to receive the same capacity payment." Further, UAE states, any variations in dispatchability, reliability and availability, either lower or greater than the avoided

resource, should be dealt with in pricing adjustments, liquidated damage provisions or other contractual remedies. In responsive comments, the Company recommends the Commission reject UAE's request because UAE is merely seeking a second opportunity to present arguments and evidence that was either already presented or could have been presented during the hearing.

For clarification, our Order is consistent with the description of pricing adjustments proposed by the Company in its direct testimony. In the matrix of summary positions, UAE had no comment with respect to the issue of pricing adjustments. Therefore, we rely on the record description of adjustments. The Company's direct testimony states adjustments will be made on a case-by-case basis subject to contractual terms and conditions. Specifically, Company testimony states, "For example, in the May 2004 Stipulation, the QF project had to meet a monthly availability of eighty-five (85) percent to receive a monthly capacity payment. If the QF does not achieve the 85% then they would not receive a capacity payment in that month. . . .Adherence to meeting its proposed availability would be based on actual measured output of the QF each month and the power purchase agreement would include terms and conditions for non-performance. Since this analysis is resource specific, it can only be applied on a case by case basis."

Relationship of the Wind Proxy Method to RFP Requirements, PURPA and FERC Rules for Determining Avoided Costs and to the Company Benchmark Resource: The Committee contends Paragraph 6 in Section III of the Order,

as written, does not require the most recently executed wind contract to comply with PURPA and FERC rules. The Committee believes the Commission's findings and conclusions do not demonstrate the payment to the most recent executed wind contract is the same as the avoided cost to be paid to a wind QF.

The Committee recommends the error of Paragraph 6 be cured by expressly requiring the most recently executed wind contract be one that results from a properly designed, renewable resource RFP which includes a Company-built benchmark and incorporates PURPA and FERC standards for determining avoided costs. In the interim, the Commission should adopt the avoided cost method proposed by the Committee, which, in summary, is to determine the avoided cost as the lower of the IRP wind resource cost estimate or the market price. Further, the Committee argues, the interim method should apply until the execution of a wind contract that results from a properly designed, renewable resource RFP which contains a Company-built benchmark, that incorporates PURPA and FERC standards for determining avoided costs, and complies with the Commission's amended report and order.

Wasatch Wind, Pioneer Ridge and Mountain West oppose the Committee's recommendations. Wasatch Wind argues the Committee makes the unsupported assertion that a properly designed, renewable resource RFP requires a Company-built option and then uses this assertion to argue the Commission's method violates federal law.

Pioneer Ridge contends the pricing established by the Commission meets the standards set forth in PURPA and the requirements of FERC for determining avoided cost, provides details of how this is so and thus concludes the Commission's decision does have a sufficient evidentiary basis. Pioneer Ridge states the price to be paid a QF, wind or non-wind, may be no more than the "incremental cost of alternative electric energy" defined in 16 U.S.C. §824a-3(d). Pioneer Ridge argues the pricing as established through the most recent competitively bid renewable RFP process meets these requirements as the pricing resulting from such process is reflected in market contracts entered into by the Company at the incremental cost to it of purchasing comparable alternative energy. Pioneer Ridge contends the logic of using the most recent renewable RFP contract as a proxy for avoided cost is to provide the best indication of the lowest price for this specific type of resource that has been recently determined through a competitive bid process.

Mountain West opposes the Committee's recommendation on the grounds it is stating a position for the first time, after hearing, and questions the Committee's preferred interim method which would appear to suffer the same defect the Committee now claims for the Commission's approved method because it too depends on the most recently executed market-based wind contract.

We affirm approval of the wind proxy method for calculating the avoided cost to the Company of acquiring wind resources up to the level of IRP cost-effective wind resources. We found the Company's avoided cost of wind resource generation is

estimated by the cost of the wind resource. A reasonable measure of this cost is the Company's most recently executed, competitively procured wind resource.

Wind Profile Adjustments in Wind Proxy Method: Wasatch Wind states the Commission did not explicitly rule on a method to account for differences in wind profiles between a QF wind resource and the market proxy and believes the Commission deferred this issue to the transmission avoided cost working group for resolution. Wasatch Wind claims the Company intends to use the GRID model to calculate the impact different wind profiles would have on indicative pricing. Wasatch Wind argues there is no evidentiary basis for the Commission to approve use of GRID to make these adjustments; only Pioneer Ridge's witness presents explicit written evidence as to the appropriate method to make such wind profile adjustments. Wasatch Wind recommends further investigation of this issue be ordered by the Commission.

In responsive comments, the Company disagrees the Commission deferred this issue to the transmission working group and states its belief that pricing adjustments would be considered on a project-specific basis. The Company states it will not know specific wind profiles until QF projects provide, as required by Schedule 38, those profiles as part of their requests for indicative pricing. If, after that time, there is disagreement on the indicative prices, the Company argues the parties may bring the issue to the Commission for resolution.

We clarify that we did not defer this issue to the transmission working group. Neither did we approve use of the GRID model for wind profile adjustments.

Pioneer Ridge's testimony on adjustments is a reasonable starting point for wind profile adjustments to produce indicative pricing for QFs up to the IRP target of wind resource procurement.

Wind Integration Costs: Wasatch Wind requests the Commission clarify its decision regarding wind integration costs. Specifically, it asks whether this part of the Order applies to wind QF pricing based on the market proxy or only to wind QFs exceeding the IRP target amount of wind. We clarify the wind integration adjustment discussed in the Order applies only to the method approved for wind QFs exceeding the IRP target amount of wind.

Renewable Energy Credits (RECs): The Company requests reconsideration of the Commission's decision allowing a QF to buy-back the RECs at the IRP value if the Company received the RECs in the most recent market-based wind contract. The Company argues avoided cost pricing for wind cannot be separated from the value of the RECs. Therefore, the Company requests the Commission find that the avoided cost pricing for wind QFs identified in the Order can only be obtained if the Company retains ownership of the RECs associated with the resource.

Wasatch Wind, Pioneer Ridge and Mountain West disagree saying it is appropriate to allow the QF to buy back the REC because it encourages wind resource development yet maintains ratepayer neutrality. These parties argue wind power facilities have attributes that exist regardless of whether RECs exist. These values are identified in the IRP and include risk mitigation against future gas and fuel price

volatility, potential environmental issues and provision of rate stability. Pioneer Ridge states RECs will not provide this benefit; RECs are a means to identify and tag this type of power so parties wanting to encourage this resource can do so by paying something extra to develop the resource. Pioneer Ridge argues it is appropriate to provide the wind QF developers the option to buy back the REC's encouragement value in case they have a better offer. If the Company has set the value appropriately, it will retain the RECs as the QF will not have a better offer.

Wasatch Wind also argues the RECs and wind resource have separate value. Wasatch Wind contends the Company's policy of purchasing RECs to fulfil the purchases of renewable wind power made by its Blue Sky customers is confirmation of the separate value of a REC from the wind resource; if the REC and the wind resource were inextricably linked, Wasatch Wind reasons, then the Company would need to purchase both the REC and the power from the wind resource to fulfil Blue Sky purchases.

We affirm the right of the QF to purchase the REC at the IRP value if the REC is included in the market-based proxy for calculating avoided costs for wind QFs up to the IRP target amount of wind. We find allowing QFs to purchase the REC if it is in the market-based wind resource contract is consistent with state policy to promote small power production facilities and also maintains ratepayer neutrality.

To ratepayers, RECs have a different and separate value from the wind resource generation, as described above by the parties. It is our understanding this issue

is not in dispute. Rather, the Company argues, the question is whether avoided cost pricing can be separated from the value of the RECs.

We agree with the Company that the avoided cost of wind is linked to the value of the REC. This is because the expected market value of the REC is included as an offset to the cost of wind to the utility and its ratepayers in evaluating the amount of cost-effective wind resource to be acquired. It is the existence of avoidable, cost-effective wind resource that is the basis for our decision approving the wind proxy method for calculation of avoided wind costs. Though linked, the avoided cost of wind and the REC value can be separated contractually. Utah Clean Energy and Western Resource Advocates testify that FERC states avoided cost rates for capacity and energy sold under contracts entered into pursuant to PURPA do not convey the RECs, in the absence of an express contractual provision. We consider the ownership of RECs to be a separable contractual issue. Ratepayers are indifferent to whether the Company contractually acquires ownership of the REC and then sells the REC to reduce the net cost of the resource or whether the Company contractually pays a price net of the REC to begin with. We are unaware of any Utah or federal law that eliminates the IRP described value of wind generation to ratepayers once the REC is sold. Indeed, our understanding of the RECs' value is to offset some of the cost of wind resource development, thus, promoting it relative to other alternatives.

A second REC issue is raised. Wasatch Wind seeks clarification of the IRP REC value. Wasatch Wind notes the $5 per megawatt hour value in the first five

years used in the IRP is based on $2 per megawatt hour levelized over the 20-year purchase life of the wind energy. Wasatch Wind requests clarification that the QF may elect either value if purchasing back the RECs. Since both values are consistent with the IRP selection of cost-effective wind resource, we clarify that either value may be elected.

Short-term Capacity Payments: UAE notes the Order is silent on UAE's request for capacity payments in the PDDRR method for shorter-term contracts. UAE respectively requests the Commission recognize firm contracts avoid capacity costs in excess of the value reflected in short-term market prices, and that payments based on a simple cycle combustion turbine (SCCT) should be included for years prior to the year in which the deferrable resource is to be built. The Company opposes this request arguing that such a payment would double-count payments. We agree. The record does not support the existence of additional avoidable SCCT fixed costs prior to the year in which the deferrable resource is to be built and therefore to add this cost would violate the ratepayer indifference standard.

Finality of the October 2005 Order: The Committee argues the October 31, 2005 Order is not final because transmission issues were deferred to a working group for later decision. Pioneer Ridge and Mountain West disagree. Pioneer Ridge and Mountain West argue the Order is final for elements of avoided costs except for site specific adjustments, for which a method of resolution was ordered. Indeed, Mountain West notes, resolving the transmission avoided cost method in a working group within 21 days was essentially the Committee's recommendation.

Our October 2005 Order is final with respect to the methods approved and issues resolved in that Order. We shall consider further testimony and argument with respect to a case-by-case method for calculating avoided transmission capacity costs and losses.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, that:

1. PacifiCorp is directed to comply with the October 31, 2005 Order and promptly file all updates to the Proxy and PDDRR methods with the Commission.
2. PacifiCorp shall promptly submit a compliance filing to demonstrate compliance with the Commission's Order directing the Company to include non-firm transmission in the GRID model based upon a 48-month history. The filing should specify the level of non-firm transmission included, provide support for the selected level, explain all changes made to the model and its inputs to incorporate non-firm transmission and explain any resulting impacts on the output of the model.

DATED at Salt Lake City, Utah, this 2nd day of February 2006.

/s / Ric Campbell, Chairman

/s / Ted. Boyer, Commissioner

/s / Ron Allen, Commissioner

Attest:

/s / Julie Orchard
Commission Secretary
G#47549