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Chas. F. McDevitt
Dean J. (Joe) Miller

April 26, 2006

Via Hand Delivery

Jean Jewell, Secretary
Idaho Public Utilities Commission
472 W. Washington St.
Boise, Idaho 83720

Re: Case No. IPC-E-05-34

Dear Ms. Jewell:

Enclosed for filing in the above matter please find the original and seven (7) copies of a Motion For Declaratory Order.

An additional copy of the document and this letter is included for return to me with your file stamp thereon.

Very Truly Yours,
McDevitt & Miller LLP

Dean J. Miller

DJM/hh

ORIGINAL

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Attorneys for Magic Wind LLC

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF MAGIC WIND LLC TO DETERMINE EXEMPTION STATUS (Corrected Caption)	**Case No. IPC-E-05-34** **MOTION FOR DECLARATORY ORDER**

COMES NOW, Magic Wind LLC ("Magic Wind") and pursuant to IPUCRP 101 *Et. Seq.* moves the Commission for a Declaratory Order, and in support thereof, respectfully shows as follows:

I.

On or about October 20, 2005, Magic Wind filed a Motion with the Commission to determine that Magic Wind was exempt from the rate eligibility cap as established by Order No. 29838.

II.

Thereafter Magic Wind supplied to Idaho Power Company ("Idaho Power") various information and documentation establishing Magic Wind's entitlement to an exemption.

III.

Upon review of the information and documentation provided, Idaho Power agreed that Magic Wind was exempt from the rate eligibility cap of Order No. 29838.

IV.

Thereafter, Magic Wind and Idaho Power commenced negotiations regarding the terms of a Purchase Power Agreement.

V.

On or about March 31, 2006, the Commission issued Order No. 30000 in Case No. PAC-E-05-06, (*In the Matter of the Application of Pacificorp for Approval of a Power Purchase Agreement with Schwendiman Wind LLC*). In general, the effect of Order No. 30000 was to approve an alternative mechanism for pricing energy deliveries that are outside the "90/110 performance band" established by Order No. 29632 ("PacifiCorp Method").

VI.

On or about April 5, 2006 Magic Wind transmitted to Idaho Power a proposed draft Purchase Power Agreement ("Proposed Agreement") that incorporated (with a modification noted below) the PacifiCorp Method approved by the Commission in Order No. 30000. The Proposed Agreement is attached hereto as Exhibit A. Magic Wind requested that Idaho Power negotiate with Magic Wind to finalize a Purchase Power Agreement consistent with the Proposed Agreement.

VII.

The Proposed Agreement modified the PacifiCorp Method so as to correct the calculation of variable operation and maintenance expense as was suggested by the Idaho Farm Energy Association in Case No. PAC-E-05-06 ("Modified PacificCorp Method"). Exhibit B, attached hereto, is the explanation for the corrected treatment of variable O&M filed by the Idaho Farm Energy Association in Case No. PAC-E-05-06. Exhibit C, attached hereto, is a spreadsheet that calculates prices for surplus energy for Idaho Power Company using the Modified PacifiCorp Method. An electronic copy with formulas intact will be provided upon request.

VIII.

On April 25, 2006, Idaho Power responded to the proposal of Magic Wind by correspondence from Randy Allphin, Idaho Power Company Contract Administrator, to Magic Wind, a copy of which is attached hereto as Exhibit D.

WHEREFORE, Magic Wind respectfully requests that the Commission determine and declare that Magic Wind is entitled to receive from Idaho Power Company a Purchase Power Agreement that establishes prices for surplus energy using the Modified PacifiCorp Method.

DATED this 26 day of April, 2006.

Respectfully submitted,

MCDEVITT & MILLER LLP

Dean J. Miller
McDevitt & Miller LLP
420 W. Bannock
Boise, ID 83702
Phone: (208) 343-7500
Fax: (208) 336-6912

Attorneys for Magic Wind LLC

CERTIFICATE OF SERVICE

I hereby certify that on the 25th day of April, 2006, I caused to be served, via the method(s) indicated below, true and correct copies of the foregoing document, upon:

Barton L. Kline	Hand Delivered	☐
Idaho Power Company	U.S. Mail	☒
1221 West Idaho Street	Fax	☐
P.O. Box 70	Fed. Express	☐
Boise, ID 83707	Email	☒
BKline@idahopower.com		

McDEVITT & MILLER LLP

BY Heather Houle, Legal Asst.

DRAFT SUBMITTED BY MAGIC WIND 4.5.06

FIRM ENERGY SALES AGREEMENT

BETWEEN

IDAHO POWER COMPANY

AND

MAGIC WIND PARK LLC

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FIRM ENERGY SALES AGREEMENT
(10 aMW or Less)

MAGIC WIND PARK LLC

Project Number: 31315500

THIS AGREEMENT, entered into on this _____ day of ____________ 2005 between MAGIC WIND, LLC, an Idaho limited liability company (Seller), and IDAHO POWER COMPANY, an Idaho corporation (Idaho Power), hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

WHEREAS, Seller will design, construct, own, maintain and operate an electric generation facility; and

WHEREAS, Seller wishes to sell, and Idaho Power is willing to purchase, firm electric energy produced by the Seller's Facility.

THEREFORE, In consideration of the mutual covenants and agreements hereinafter set forth, the Parties agree as follows:

ARTICLE I: DEFINITIONS

As used in this Agreement and the appendices attached hereto, the following terms shall have the following meanings:

1.1 "Commission" - The Idaho Public Utilities Commission.

1.2 "Contract Year" - The period commencing each calendar year on the same calendar date as the Operation Date and ending 364 days thereafter.

1.3 "Designated Dispatch Facility" - Idaho Power's Systems Operations Group, or any subsequent group designated by Idaho Power.

1.4 "Disconnection Equipment" - All equipment specified in Schedule 72 and the Generation Interconnection Process and any additional equipment specified in Appendix B.

1.5 "Facility" - That electric generation facility described in Appendix B of this Agreement.

1.6 "First Energy Date" - The day commencing at 0001 hours, Mountain Time, following the day that Seller has satisfied the requirements of Article IV and the Seller begins delivering energy to Idaho Power's system at the Point of Delivery.

1.7 "Generation Interconnection Process" – Idaho Power's generation interconnection application and engineering review process developed to ensure a safe and reliable generation interconnection in compliance with all applicable regulatory requirements, Prudent Electrical Practices and national safety standards.

1.8 "Inadvertent Energy" – Electric energy Seller does not intend to generate. Inadvertent energy is more particularly described in paragraph 7.3 of this Agreement.

1.9 "Interconnection Facilities" - All equipment specified in Schedule 72 and the Generation Interconnection Process and any additional equipment specified in Appendix B.

1.10 "Initial Capacity Determination" – The process by which Idaho Power confirms that under normal or average design conditions the Facility will generate at no more than 10 average MW per month and is therefore eligible to be paid the published rates in accordance with Commission Order No. 29632.

1.11 "Losses" – The loss of electrical energy expressed in kilowatt hours (kWh) occurring as a result of the transformation and transmission of energy between the point where the Facility's energy is metered and the point the Facility's energy is delivered to the Idaho Power electrical system. The loss calculation formula will be as specified in Appendix B of this Agreement.

~~1.12 "Market Energy Cost" – Eighty-five percent (85%) of the weighted average of the daily on-peak and off-peak Dow Jones Mid-Columbia Index (Dow Jones Mid-C Index) prices for non-firm energy. If the Dow Jones Mid Columbia Index price is discontinued by the reporting agency, both Parties will mutually agree upon a replacement index, which is similar to the Dow Jones Mid-Columbia Index. The selected replacement index will be consistent with other similar agreements and a commonly used index by the electrical industry.~~

1.12 Intentionally left blank.

1.13 "Material Breach" – A Default (paragraph 22.2.1) subject to paragraph 22.2.2.

1.14 "Maximum Capacity Amount" – The maximum capacity (MW) of the Facility will be as specified in Appendix B of this Agreement.

1.15 "Metering Equipment" - All equipment specified in Schedule 72, the Generation Interconnection Process, this Agreement and any additional equipment specified in Appendix B required to measure, record and telemeter power flows between the Seller's electric generation plant and Idaho Power's system.

1.16 "Net Energy" – All of the electric energy produced by the Facility, less Station Use, less Losses, expressed in kilowatt hours (kWh). Seller commits to deliver all Net Energy to Idaho Power at the Point of Delivery for the full term of the Agreement. Net Energy does not include Inadvertent Energy.

1.17 "Operation Date" – The day commencing at 0001 hours, Mountain Time, following the day that all requirements of paragraph 5.2 have been completed.

1.18 "Point of Delivery" – The location specified in Appendix B, where Idaho Power's and the Seller's electrical facilities are interconnected.

1.19 "Prudent Electrical Practices" – Those practices, methods and equipment that are commonly and ordinarily used in electrical engineering and operations to operate electric equipment lawfully, safely, dependably, efficiently and economically.

1.20 "Scheduled Operation Date" – The date specified in Appendix B when Seller anticipates achieving the Operation Date.

1.21 "Schedule 72" – Idaho Power's Tariff No 101, Schedule 72 or its successor schedules as approved by the Commission.

1.22 "Season" – The three periods identified in paragraph 6.2.1 of this Agreement.

1.23 "Special Facilities" - Additions or alterations of transmission and/or distribution lines and transformers as described in Appendix B, Schedule 72 or the Generation Interconnection Process required to safely interconnect the Seller's Facility to the Idaho Power system.

1.24 "Station Use" – Electric energy that is used to operate equipment that is auxiliary or otherwise related to the production of electricity by the Facility.

1.25 "Surplus Energy" – (1) Net Energy produced by the Seller's Facility and delivered to the Idaho Power electrical system during the month which exceeds 110% of the monthly Net Energy Amount for the corresponding month specified in paragraph 6.2. or (2) If the Net Energy produced by the Seller's Facility and delivered to the Idaho Power electrical system during the month is less than 90% of the monthly Net Energy Amount for the corresponding month specified in paragraph 6.2, then all Net Energy delivered by the Facility to the Idaho Power electrical system for that given month or (3) All Net Energy produced by the Seller's Facility and delivered by the Facility to the Idaho Power electrical system prior to the Operation Date.

1.26 "Total Cost of the Facility" - The total cost of structures, equipment and appurtenances.

ARTICLE II: NO RELIANCE ON IDAHO POWER

2.1 Seller Independent Investigation - Seller warrants and represents to Idaho Power that in entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Idaho Power in connection with the transactions contemplated by this Agreement.

2.2 Seller Independent Experts - All professionals or experts including, but not limited to, engineers, attorneys or accountants, that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller.

ARTICLE III: WARRANTIES

3.1 No Warranty by Idaho Power - Any review, acceptance or failure to review Seller's design, specifications, equipment or facilities shall not be an endorsement or a confirmation by Idaho Power and Idaho Power makes no warranties, expressed or implied, regarding any aspect of

Seller's design, specifications, equipment or facilities, including, but not limited to, safety, durability, reliability, strength, capacity, adequacy or economic feasibility.

3.2 Qualifying Facility Status - Seller warrants that the Facility is a "Qualifying Facility," as that term is used and defined in 18 CFR §292.207. After initial qualification, Seller will take such steps as may be required to maintain the Facility's Qualifying Facility status during the term of this Agreement and Seller's failure to maintain Qualifying Facility status will be a Material Breach of this Agreement. Idaho Power reserves the right to review the Seller's Qualifying Facility status and associated support and compliance documents at anytime during the term of this Agreement.

ARTICLE IV: CONDITIONS TO ACCEPTANCE OF ENERGY

4.1 Prior to the First Energy Date and as a condition of Idaho Power's acceptance of deliveries of energy from the Seller, Seller shall:

4.1.1 Submit proof to Idaho Power that all licenses, permits or approvals necessary for Seller's operations have been obtained from applicable federal, state or local authorities, including, but not limited to, evidence of compliance with Subpart B, 18 CFR 292.207.

4.1.2 Opinion of Counsel - Submit to Idaho Power an Opinion Letter signed by an attorney admitted to practice and in good standing in the State of Idaho providing an opinion that Seller's licenses, permits and approvals as set forth in paragraph 4.1.1 above are legally and validly issued, are held in the name of the Seller and, based on a reasonable independent review, counsel is of the opinion that Seller is in substantial compliance with said permits as of the date of the Opinion Letter. The Opinion Letter will be in a form acceptable to Idaho Power and will acknowledge that the attorney rendering the opinion understands that Idaho Power is relying on said opinion. Idaho Power's acceptance of the form will not be unreasonably withheld. The Opinion Letter will be governed by and shall be interpreted in accordance with the legal opinion accord of the American Bar Association Section of Business Law (1991).

4.1.3 Initial Capacity Determination - Submit to Idaho Power such data as Idaho Power may reasonably require to perform the Initial Capacity Determination. Such data will include but not be limited to, equipment specifications, prime mover data, resource characteristics, normal and/or average operating design conditions and Station Use data. Upon receipt of this information, Idaho Power will review the provided data and if necessary, request additional data to complete the Initial Capacity Determination within a reasonable time.

4.1.4 Engineer's Certifications - Submit an executed Engineer's Certification of Design & Construction Adequacy and an Engineer's Certification of Operations and Maintenance (O&M) Policy as described in Commission Order No. 21690. These certificates will be in the form specified in Appendix C but may be modified to the extent necessary to recognize the different engineering disciplines providing the certificates.

4.1.5 Insurance - Submit written proof to Idaho Power of all insurance required in Article XV.

4.1.6 Interconnection – Provide written proof to Idaho Power that all Schedule 72 and Generation Interconnection Process requirements have been completed.

4.1.7 Written Acceptance – Request and obtain written confirmation from Idaho Power that all conditions to acceptance of energy have been fulfilled. Such written confirmation shall be provided within a commercially reasonable time following the Seller's request and will not be unreasonably withheld by Idaho Power.

ARTICLE V: TERM AND OPERATION DATE

5.1 Term - Subject to the provisions of paragraph 5.2 below, this Agreement shall become effective on the date first written and shall continue in full force and effect for a period of twenty (20) Contract Years from the Operation Date.

5.2 Operation Date - The Operation Date may occur only after the Facility has achieved all of the following:

a) Achieved the First Energy Date.

b) Commission approval of this Agreement in a form acceptable to Idaho Power has been received.

c) Seller has demonstrated to Idaho Power's satisfaction that the Facility is complete and able to provide energy in a consistent, reliable and safe manner and has requested an Operation Date in written form.

d) Seller has requested an Operation Date from Idaho Power in a written format.

e) Seller has received written confirmation from Idaho Power of the Operation Date. This confirmation will not be unreasonably withheld by Idaho Power.

5.3 Seller's failure to achieve the Operation Date within ten (10) months of the Scheduled Operation Date will be an event of default.

ARTICLE VI: PURCHASE AND SALE OF NET ENERGY

6.1 Delivery and Acceptance of Net Energy - Except when either Party's performance is excused as provided herein, Idaho Power will purchase and Seller will sell all of the Net Energy to Idaho Power at the Point of Delivery. All Inadvertent Energy produced by the Facility will also be delivered by the Seller to Idaho Power at the Point of Delivery. At no time will the total amount of Net Energy and/or Inadvertent Energy produced by the Facility and delivered by the Seller to the Point of Delivery exceed the Maximum Capacity Amount.

6.2 Net Energy Amounts - Seller intends to produce and deliver Net Energy in the following monthly amounts:

6.2.1 Initial Year Monthly Net Energy Amounts:

	Month	**kWh**
Season 1	March	5,395,947
	April	4,370,833
	May	4,105,320
	July	3,401,877

Season 2	August	2,791,276
	November	4,394,931
	December	5,206,030
Season 3	June	4,962,172
	September	4,272,864
	October	4,102,945
	January	4,580,098
	February	5,720,491

6.2.2 Ongoing Monthly Net Energy Amounts - Seller shall initially provide Idaho Power with one year of monthly generation estimates (Initial Year Monthly Net Energy Amounts) and beginning at the end of month nine and every three months thereafter provide Idaho Power with an additional three months of forward generation estimates. This information will be provided to Idaho Power by written notice in accordance with paragraph 28.1, no later than 5:00 PM of the 5th day following the end of the previous month. If the Seller does not provide the Ongoing Monthly Net Energy amounts in a timely manner, Idaho Power will use the most recent 3 months of the Initial Year Monthly Net Energy Amounts specified in paragraph 6.2.1 for the next 3 months of monthly Net Energy amounts.

6.2.3 Seller's Adjustment of Net Energy Amount –

6.2.3.1 No later than the Operation Date, by written notice given to Idaho Power in accordance with paragraph 28.1, the Seller may revise all of the previously provided Initial Year Monthly Net Energy Amounts.

6.2.3.2 Beginning with the end of the 3rd month after the Operation Date and at the end of every third month thereafter: (1) the Seller may not revise the immediate next three months of previously provided Net Energy Amounts, (2) but by written notice given to Idaho Power in accordance with paragraph 28.1, no later than 5:00 PM of the 5th day following the end of the previous month, the Seller may revise all other previously provided Net Energy Amounts. Failure to provide timely written notice of changed amounts will be deemed to be an election of no change.

6.2.4 Idaho Power Adjustment of Net Energy Amount – If Idaho Power is excused from accepting the Seller's Net Energy as specified in paragraph 14.2.1 or if the Seller declares a Suspension of Energy Deliveries as specified in paragraph 14.3.1 and the Seller's declared Suspension of Energy Deliveries is accepted by Idaho Power, the Net Energy Amount as specified in paragraph 6.2 for the specific month in which the reduction or suspension under paragraph 14.2.1 or 14.3.1 occurs will be reduced in accordance with the following:

Where:

NEA = Current Month's Net Energy Amount (Paragraph 6.2)

SGU =

a.) If Idaho Power is excused from accepting the Seller's Net Energy as specified in paragraph 14.2.1 this value will be equal to the percentage of curtailment as specified by Idaho Power multiplied by the TGU as defined below.

b.) If the Seller declares a Suspension of Energy Deliveries as specified in paragraph 14.3.1 this value will be the sum of the individual generation units size ratings as specified in Appendix B that are impacted by the circumstances causing the Seller to declare a Suspension of Energy Deliveries.

TGU = Sum of all of the individual generator ratings of the generation units at this Facility as specified in Appendix B of this agreement.

RSH = Actual hours the Facility's Net Energy deliveries were either reduced or suspended under paragraph 14.2.1 or 14.3.1

TH = Actual total hours in the current month

Resulting formula being:

$$\text{Adjusted Net Energy Amount} = NEA - \left(\left(\frac{SGU}{TGU} \times NEA \right) \times \left(\frac{RSH}{TH} \right) \right)$$

This Adjusted Net Energy Amount will be used in applicable Surplus Energy calculations for only the specific month in which Idaho Power was excused from accepting the Seller's Net Energy or the Seller declared a Suspension of Energy.

6.3 Unless excused by an event of Force Majeure, Seller's failure to deliver Net Energy in any Contract Year in an amount equal to at least ten percent (10%) of the sum of the Initial Year Net Energy Amounts as specified in paragraph 6.2 shall constitute an event of default.

ARTICLE VII: PURCHASE PRICE AND METHOD OF PAYMENT

7.1 Net Energy Purchase Price – For all Net Energy, Idaho Power will pay the non-levelized energy price in accordance with Commission Order 29646 with seasonalization factors applied:

	Season 1 - (73.50 %)	Season 2 - (120.00 %)	Season 3 - (100.00 %)
Year	Mills/kWh	Mills/kWh	Mills/kWh
2006	37.85	61.80	51.50
2007	38.73	63.23	52.69
2008	39.62	64.68	53.90
2009	40.53	66.17	55.14
2010	41.46	67.69	56.41
2011	42.42	69.25	57.71
2012	43.39	70.85	59.04
2013	44.39	72.48	60.40
2014	45.42	74.16	61.80
2015	46.47	75.86	63.22
2016	47.54	77.62	64.68
2017	48.63	79.40	66.17
2018	49.76	81.24	67.70
2019	50.91	83.11	69.26
2020	52.07	85.02	70.85
2021	53.28	86.99	72.49
2022	54.51	88.99	74.16
2023	55.76	91.04	75.87
2024	57.05	93.14	77.62
2025	58.37	95.29	79.41
2026	59.72	97.50	81.25
2027	61.09	99.74	83.12

7.2 Surplus Energy Price - For all Surplus Energy, Idaho Power shall pay to the Seller the ~~current month's Market Energy Cost or the Net Energy Purchase Price specified in paragraph 7.1,~~

~~whichever is lower.~~following price during each applicable Season and year:

Year	Season 1 Mills/kWh	Season 2 Mills/kWh	Season 3 Mills/kWh
2006	37.85	47.29	47.29
2007	38.73	48.39	48.39
2008	39.62	49.51	49.51
2009	40.53	50.67	50.67
2010	41.46	51.85	51.85
2011	42.42	53.05	53.05
2012	43.39	54.29	54.29
2013	44.39	55.55	55.55
2014	45.42	56.85	56.85
2015	46.47	58.17	58.17
2016	47.54	59.52	59.52
2017	48.63	60.91	60.91
2018	49.76	62.33	62.33
2019	50.91	63.78	63.78
2020	52.07	65.27	65.27
2021	53.28	66.79	66.79
2022	54.51	68.34	68.34
2023	55.76	69.93	69.93
2024	57.05	71.56	71.56
2025	58.37	73.23	73.23
2026	59.72	74.94	74.94
2027	61.09	76.68	76.68

7.3 Inadvertent Energy –

7.3.1 Inadvertent Energy is electric energy produced by the Facility, expressed in kWh, which the Seller delivers to Idaho Power at the Point of Delivery that exceeds 10,000 kW multiplied by the hours in the specific month in which the energy was delivered. (For example January contains 744 hours. 744 hours times 10,000 kW = 7,440,000 kWh. Energy delivered in January in excess of 7,440, 000 kWh in this example would be Inadvertent Energy.)

7.3.2 Although Seller intends to design and operate the Facility to generate no more than 10 average MW and therefore does not intend to generate Inadvertent Energy, Idaho Power will accept Inadvertent Energy that does not exceed the Maximum Capacity Amount but

REMAINING PAGES OF AGREEMENT ARE NOT ATTACHED BECAUSE THERE IS NO PROPOSED DEVIATION FROM THE IPCo TEMPLATE AGREEMENT.

IDAHO FARM ENERGY ASSOCIATION

March 8, 2006

Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington St.
Boise, ID 83702-5983

Re: Comments on PAC-E-05-09

Dear Ms. Jewell:

The Idaho Farm Energy Association provides the following comments on the Amended Agreement filed with the Commission on January 27, 2006 in the above-referenced matter. The Idaho Farm Energy Association is a nonprofit corporation formed in January 2006 to promote rural economic development through on-farm renewable energy projects in the State of Idaho. On-farm renewable energy projects can shelter consumers from rising fuel prices, contribute to local economies, provide direct income for farmers and ranchers, increase diversity of fuel supply, and reduce our dependence on foreign fuels.

We support approval of the Schwendiman Amended Agreement and view its modified 90/110 banding mechanism as a significant improvement over the prior version of the band. However, the methodology used to separate the capacity and energy price components in this Amended Agreement contains an important error which must be corrected if these new contract terms are to be applied to other projects. In addition, we believe that the 90/110 performance band remains an unjustified reduction from full avoided cost prices. We also object to the failure of the methodology to recognize that deliveries below the 90% band still have capacity value.

Rather than persisting with the 90/110 banding requirement, we believe all parties would be better served by requiring that wind projects provide forecasts from pre-approved advanced forecasting services. This is the best way to minimize the cost of integrating wind energy.

1. Non-Conforming Energy Price Calculation is Erroneous

The "non-conforming energy" price is too low because it fails to include the full value of variable operations and maintenance costs for the surrogate avoided resource. A portion of variable O&M costs were included in the capacity component of the published rates, which has the

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oise, ID 83702

208-859-1882
208-495-1555

effect of reducing the energy component (and thus the non-conforming energy price).

Specifically, all of the variable O&M up to the capacity factor of the peaking resource has been allocated to capacity. Therefore, the equivalent amount of energy from the SAR combined cycle would have no variable O&M in its avoided energy costs. This cannot be correct. If this energy is displaced by wind deliveries, every kWh delivered would save variable O&M at the SAR. Variable O&M is defined as O&M costs which vary with the number of kWh generated.

It is important to note that all of the variable O&M of the peaking resource is assigned to capacity, not just the difference in variable O&M between the peaking resource and the SAR. In fact, since the variable O&M of the peaking resource is higher than the SAR this has an even greater impact on the number of kWh with no associated variable O&M. The attached report of Dr. Don Reading is incorporated by reference to these comments, and provides a more detailed explanation of this error.

In essence, only the fixed costs of a peaking resource should be included in the capacity component. All variable costs should be allocated to the energy component. Obviously variable O&M costs, by definition, are not fixed costs. Simply put, variable O&M costs are more akin to fuel costs than capital costs.

The significance of this error is directly related to the assumed capacity factor of the peaking resource. In the case of Pacificorp, the assumed capacity factor is 18%. While this error has a modest impact on the non-conforming energy price under the Amended Agreement, it would have a much more significant impact if applied to Idaho Power, which assumes a 59% capacity factor, as noted in Dr Reading's letter.

Dr. Reading confirmed that Pacificorp included a portion of variable O&M in capacity in its avoided cost filings in Oregon and Utah. However in both cases, this was not an important issue. In those jurisdictions, the division between capacity and energy is only used to allocate the total avoided costs to different time of delivery periods. Thus, in those other states, the error was harmless because it did not reduce total average price.

However in the Amended Agreement, this erroneous allocation has a very real impact on the actual price paid for non-conforming energy. Any variable costs allocated to capacity prices unfairly reduces the non-conforming energy price. Unlike in Oregon and Utah, this issue has significant relevance to total average price.

The Amended Agreement is signed, final, and should be approved. However, the Commission should make specific findings that the exclusion of variable O&M costs from the energy-only value of the published rates is inappropriate and should not be repeated for future contracts.

2. Deliveries Below 90% Deserve Some Capacity Credit

Even if a wind project delivers less than 90% of its projected output, its deliveries still improve system reliability. That is, it still has capacity value. By way of example, if a utility-owned resource suffers a major forced outage -- or there is a lack of hydro resource -- those resources are not removed from ratebase. The utility will still receive full compensation for building the project even though it has failed to meet its projected performance. Unlike a utility owned resource, the wind project is only paid for what it delivers; however, failing to meet the 90% standard does not mean that deliveries below 90% should not receive some capacity credit.

3. The Amended Agreement Is An Improvement, but the 90/110 Performance Band Continues To Be An Inappropriate Policy

The modified form of the 90/110 band reflected in the Amended Agreement is an improvement over the market-based non-conforming energy price set in prior standard PURPA contracts approved by the Commission. Future PURPA projects in each utilities' service territory should have the *option* of choosing the terms of the Amended Agreement (with the variable O&M correction discussed above).

However, we believe the Commission should more strongly encourage and provide guidance to utilities and wind projects to develop contract terms that are "similarly rigorous" to the 90/110 band. Order 29880.

The Commission has heard the criticisms of the 90/110 band. The simple fact is that no wind forecasting technology exists to provide a forecast of monthly production within 10% accuracy a quarter in advance. Nor is such information valuable to operating the utility system. The 90/110 mechanism simply serves to reduce prices from full avoided costs. We believe this is forbidden by PURPA, and that better alternatives can be found.

Wind forecasts, like hydro forecasts, are exponentially more accurate in the near term. In the time horizons actually used by utilities for operational planning (such as real time and day ahead markets), high quality wind forecasts are available. Utilities are far better served by near term forecasts with higher accuracy than speculative forecasts three months in advance. Moreover, the 90/110 band drives wind projects to provide artificially low forecasts to utilities, undercutting the very purpose of its existence.

In Order 29880 (at page 3), the Commission stated that the 90/110 band serves as an "incentive for the QF to make the most reliable estimates possible." In fact, the band serves as an incentive for the project to submit artificially low forecasts. At higher penetrations of wind energy on the grid, this could create a situation where utilities are securing power on the market or allocating resources unnecessarily – a poor outcome for ratepayers.

We believe that new non-price terms can be developed to the advantage of utilities and wind developers. We suggest the Commission favorably recommend that utilities and developers carefully explore replacing the 90/110 band with a combination of the new, high resolution short-term forecasting services which have become available and the mechanical availability guarantee ("MAG"). Using these third party forecasting services has become increasingly common in the industry. This will provide utilities with the most accurate forecast of wind production for use in operational planning and resource dispatch. This was the Commission's primary goal in using the 90/110 band.

If desirable, longer term forecasts can still be provided for a utility's strategic planning process, but without the pricing terms that have created an incentive for wind projects to submit artificially low forecasts. Also, including the MAG provision ensures that a project's operator is focused on doing the best possible job with those things that can be controlled.

We submit that professional, independent forecasts and the MAG, taken together, are "similarly rigorous" compared to the 90/110 band. In fact, they should provide far more useful information for operational planners. Short term forecasts from experienced firms have a high degree of accuracy, and long term forecasts, if needed, will not be skewed downward due to the wind projects' natural tendency to hedge against the 90/110 band. The MAG provision will ensure a high degree of project availability and maximum energy deliveries.

Thank you for your consideration of these comments.

Sincerely,

Brian Jackson
President, Idaho Farm Energy Association

Cc:

Lisa Nordstrom
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March 8, 2006

ECONOMIC RESEARCH
AND ANALYSIS

Ben Johnson®
Associates, Inc

Brian Jackson
President
Idaho Farm Energy Association
515 N. 27th St.
Boise, ID 83702

Dear Mr. Jackson:

Your Association has asked me to review the calculations related to the price for Non-Conforming Energy in the Schwendiman wind energy contract and the implications of the modified 90/110 Performance Band mechanism. The following analysis indicates that the new mechanism is a major improvement over the existing mechanism. However PacifiCorp's method of calculation of the Non-Conforming Energy Price contains a significant theoretical flaw that needs be corrected before the mechanism is generally applied in future avoided cost calculations.

Modified 90/110 Performance Band

The Modified Band is superior to the current methodology because it eliminates market price risk from the contract. The forecast of revenues for the wind projects will be far less volatile because they are no longer exposed to natural gas prices. For the ratepayers, there will now be an economic incentive for accurate forecasting at all times. Under the current mechanism, there is no forecasting incentive when 85% of the prices at Mid-C exceed the contract price. This situation has occurred in the past.

The basis of fixed price contracts is to eliminate market price risks for both parties. The avoided costs represent a common view as to the long term cost of producing electricity. One problem with the current 90/110 mechanism is that it violated this basic compact. Rather than using the agreed upon prices, it uses market prices <u>only</u> if they are lower. The one-sided nature of this mechanism is unfairly biased against wind projects and artificially reduces supply. This in turn increases costs to ratepayers in the long run, since they will then buy more energy from less economic sources. The Modified Band returns to the common view of forecasted energy prices.

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Non-Conforming Energy Price

PacifiCorp has used a common approach to dividing the total avoided cost, calculated with the SAR method, between capacity and energy. In jurisdictions which use time differentiated avoided costs, the value of reliability is separated from the value of energy. If the fixed cost of a combined cycle is used to price capacity, a competitive market could add an infinite number of simple cycle combustion turbines (SCCT) and the owners of those turbines would reap above market returns.

Hence, it is generally recognized that the fixed cost of owning the least cost peaking resource, such as an SCCT, is the appropriate proxy for pricing capacity, regardless of what type of power plant is used as the SAR.

With this approach all other costs of the SAR, including the balance of the capital costs, are allocated to energy. Essentially, any additional fixed costs of the SAR compared to the peaking resource is justified on the basis of operating cost savings.

If the additional capital costs of the combined cycle SAR are not allocated to the energy price, then only resources operating at or below the heat rate of the SAR would be economic. However, there are obviously times when peaking resources, such as Bennett Mountain, will operate even though their operating costs are higher. This can occur for a variety of reasons such as load balancing, mitigating transmission constraints, replacement of outages of other units, etc.. Adding the extra capital costs of the SAR to energy has the effect of increasing the energy price to account for periods when more expensive resources are operating.

PacifiCorp Methodology Error

There is a theoretical flaw in PacifiCorp's avoided cost calculation methodology. The Company includes variable O&M in the SCCT's fixed costs. While this is consistent with the way PacifiCorp calculates avoided capacity prices in Utah and Oregon, it is simply incorrect. In economic terms, the task here is to determine the change in cost due to a change in demand (kW). Operating costs (kWh) are not part of this calculation. The change in variable O&M due to a change in kW is zero. There is no justification for treating variable O&M costs differently than variable fuel costs.

In both Oregon and Utah, the avoided capacity price is simply used to allocate total avoided costs between time periods. Therefore, PacifiCorp's methodology does not reduce total avoided costs. It only shifts a minor amount of avoided costs between on-peak and off-peak periods. In the Schwendiman case, this flawed methodology reduces the price of Non-Conforming Energy. Therefore, it causes an unfair loss to the projects that will be subject to this approach.

Applying the Methodology to Idaho Power

The size of the PacifiCorp error is determined by the capacity factor assumed for the SCCT. PacifiCorp uses an 18% capacity factor based on their 2004 IRP Update. If this error isn't corrected, it will have a far larger impact if the method is applied to Idaho Power. Idaho Power assumes an SCCT capacity factor of 59% in their 2004 IRP. For 2006, the PacifiCorp calculation reduces the Non-Conforming Energy Price by 1.86 \$/MWh. If applied to Idaho Power, the error will equal 2.80 \$/MWh.

Attached is a calculation of Non-Conforming Energy Prices for Idaho Power using its 2004 IRP assumptions and eliminating variable O&M from capacity prices. To adjust for seasonal prices, I assumed that no avoided capacity costs be allocated to the three off peak months and that the Non-Conforming Energy Prices be assigned in the other two seasons. The result is that most of the difference in seasonal prices is assigned to capacity prices, which is logical.

It should be noted that there is a small rounding error when applying Idaho Power's normal seasonality factor to the March–May period. The actual factor is 73.33%, which has been rounded to 73.5% in the current SAR model.

Recommendation

The a theoretical flaw in PacifiCorp's avoided cost calculation methodology needs to be corrected for the reasons stated above. Variable O&M should not be included in fixed costs. In future contracts PacifiCorp needs to fix this error and the methodology should not be extended to Idaho Power, or any other utility without correction.

Sincerely,

Don C. Reading

Don C. Reading, PhD
Consulting Economist, VP

IDAHO POWER - SAR WITH PEAK CREDIT METHOD

Capacity Cost split by Bennett Mtn SCCT from 2004 IRP Study

	$/MWH					
Year	CCCT Fixed Costs	SCCT Fixed Costs	Capitalized Energy	Fuel Costs	Total Fuel Costs	Total Avoided Cost
2006	13.61	6.59	7.01	37.89	44.91	51.50
2007	13.92	6.74	7.18	38.77	45.95	52.69
2008	14.24	6.88	7.36	39.66	47.02	53.90
2009	14.57	7.03	7.54	40.57	48.11	55.14
2010	14.91	7.19	7.72	41.50	49.23	56.41
2011	15.26	7.34	7.91	42.46	50.37	57.71
2012	15.61	7.50	8.11	43.43	51.54	59.04
2013	15.97	7.67	8.30	44.43	52.74	60.40
2014	16.34	7.83	8.51	45.46	53.96	61.80
2015	16.72	8.00	8.72	46.50	55.22	63.22
2016	17.11	8.18	8.93	47.57	56.50	64.68
2017	17.51	8.36	9.15	48.66	57.81	66.17
2018	17.91	8.54	9.37	49.78	59.16	67.70
2019	18.33	8.72	9.60	50.93	60.53	69.26
2020	18.75	8.92	9.84	52.10	61.94	70.85
2021	19.19	9.11	10.08	53.30	63.38	72.49
2022	19.64	9.31	10.33	54.52	64.85	74.16
2023	20.09	9.51	10.58	55.78	66.36	75.87
2024	20.56	9.72	10.84	57.06	67.90	77.62
2025	21.04	9.93	11.11	58.37	69.48	79.41
2026	21.53	10.15	11.38	59.72	71.10	81.25
2027	22.03	10.37	11.66	61.09	72.75	83.12
2028	22.54	10.60	11.95	62.49	74.44	85.04
2029	23.07	10.83	12.24	63.93	76.17	87.00
2030	23.61	11.06	12.54	65.40	77.95	89.01

IDAHO POWER - SAR WITH PEAK CREDIT METHOD

Allocation of Peak Credit to Seasonal Periods

CAPACITY PRICE			NON-CONFORMING ENERGY PRICE				TOTAL SEASONAL PRICE			
Mar-May 73.3% Mo: 3	Jun-Sep 120.0% 4	Oct-Feb 100.0% 5	Mar-May 73.3% 3	Jun-Sep 120.0% 4	Oct-Feb 100.0% 5	Wtd Avg 12	Mar-May 73.3% 3	Jun-Sep 120.0% 4	Oct-Feb 100.0% 5	Wtd Avg 12
-	14.51	4.21	37.77	47.29	47.29	44.91	37.77	61.80	51.50	51.50
-	14.84	4.30	38.64	48.39	48.39	45.95	38.64	63.22	52.69	52.69
-	15.17	4.39	39.53	49.51	49.51	47.02	39.53	64.68	53.90	53.90
-	15.50	4.48	40.44	50.67	50.67	48.11	40.44	66.17	55.14	55.14
-	15.85	4.57	41.37	51.85	51.85	49.23	41.37	67.70	56.41	56.41
-	16.20	4.66	42.32	53.05	53.05	50.37	42.32	69.26	57.71	57.71
-	16.56	4.76	43.30	54.29	54.29	51.54	43.30	70.85	59.04	59.04
-	16.93	4.85	44.30	55.55	55.55	52.74	44.30	72.48	60.40	60.40
-	17.31	4.95	45.32	56.85	56.85	53.96	45.32	74.16	61.80	61.80
-	17.70	5.05	46.36	58.17	58.17	55.22	46.36	75.87	63.22	63.22
-	18.09	5.16	47.43	59.52	59.52	56.50	47.43	77.61	64.68	64.68
-	18.49	5.26	48.52	60.91	60.91	57.81	48.52	79.40	66.17	66.17
-	18.91	5.37	49.64	62.33	62.33	59.16	49.64	81.23	67.70	67.70
-	19.33	5.48	50.79	63.78	63.78	60.53	50.79	83.11	69.26	69.26
-	19.76	5.59	51.96	65.27	65.27	61.94	51.96	85.03	70.85	70.85
-	20.20	5.70	53.16	66.79	66.79	63.38	53.16	86.99	72.49	72.49
-	20.65	5.82	54.38	68.34	68.34	64.85	54.38	88.99	74.16	74.16
-	21.11	5.94	55.64	69.93	69.93	66.36	55.64	91.05	75.87	75.87
-	21.58	6.06	56.92	71.56	71.56	67.90	56.92	93.15	77.62	77.62
-	22.07	6.18	58.24	73.23	73.23	69.48	58.24	95.30	79.41	79.41
-	22.56	6.31	59.58	74.94	74.94	71.10	59.58	97.50	81.25	81.25
-	23.06	6.44	60.96	76.68	76.68	72.75	60.96	99.75	83.12	83.12
-	23.58	6.57	62.36	78.47	78.47	74.44	62.36	102.05	85.04	85.04
-	24.10	6.70	63.80	80.30	80.30	76.17	63.80	104.40	87.00	87.00
-	24.64	6.84	65.27	82.17	82.17	77.95	65.27	106.81	89.01	89.01

IDAHO POWER - SAR WITH PEAKER CREDIT METHOD

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2028	22.54	10.60	11.95	62.49	74.44	85.04
2029	23.07	10.83	12.24	63.93	76.17	87.00
2030	23.61	11.06	12.54	65.40	77.95	89.01

IDAHO POWER - SAR WITH PEAKER CREDIT METHOD

Allocation of Peak Credit to Seasonal Periods

CAPACITY PRICE			SURPLUS ENERGY PRICE				TOTAL SEASONAL PRICE			
Mar-May 73.3%	Jun-Sep 120.0%	Oct-Feb 100.0%	Mar-May 73.3%	Jun-Sep 120.0%	Oct-Feb 100.0%	Wtd Avg	Mar-May 73.3%	Jun-Sep 120.0%	Oct-Feb 100.0%	Wtd Avg
Mo: 3	4	5	3	4	5	12	3	4	5	12
-	14.51	4.21	37.77	47.29	47.29	44.91	37.77	61.80	51.50	51.50
-	14.84	4.30	38.64	48.39	48.39	45.95	38.64	63.22	52.69	52.69
-	15.17	4.39	39.53	49.51	49.51	47.02	39.53	64.68	53.90	53.90
-	15.50	4.48	40.44	50.67	50.67	48.11	40.44	66.17	55.14	55.14
-	15.85	4.57	41.37	51.85	51.85	49.23	41.37	67.70	56.41	56.41
-	16.20	4.66	42.32	53.05	53.05	50.37	42.32	69.26	57.71	57.71
-	16.56	4.76	43.30	54.29	54.29	51.54	43.30	70.85	59.04	59.04
-	16.93	4.85	44.30	55.55	55.55	52.74	44.30	72.48	60.40	60.40
-	17.31	4.95	45.32	56.85	56.85	53.96	45.32	74.16	61.80	61.80
-	17.70	5.05	46.36	58.17	58.17	55.22	46.36	75.87	63.22	63.22
-	18.09	5.16	47.43	59.52	59.52	56.50	47.43	77.61	64.68	64.68
-	18.49	5.26	48.52	60.91	60.91	57.81	48.52	79.40	66.17	66.17
-	18.91	5.37	49.64	62.33	62.33	59.16	49.64	81.23	67.70	67.70
-	19.33	5.48	50.79	63.78	63.78	60.53	50.79	83.11	69.26	69.26
-	19.76	5.59	51.96	65.27	65.27	61.94	51.96	85.03	70.85	70.85
-	20.20	5.70	53.16	66.79	66.79	63.38	53.16	86.99	72.49	72.49
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-	21.11	5.94	55.64	69.93	69.93	66.36	55.64	91.05	75.87	75.87
-	21.58	6.06	56.92	71.56	71.56	67.90	56.92	93.15	77.62	77.62
-	22.07	6.18	58.24	73.23	73.23	69.48	58.24	95.30	79.41	79.41
-	22.56	6.31	59.58	74.94	74.94	71.10	59.58	97.50	81.25	81.25
-	23.06	6.44	60.96	76.68	76.68	72.75	60.96	99.75	83.12	83.12
-	23.58	6.57	62.36	78.47	78.47	74.44	62.36	102.05	85.04	85.04
-	24.10	6.70	63.80	80.30	80.30	76.17	63.80	104.40	87.00	87.00
-	24.64	6.84	65.27	82.17	82.17	77.95	65.27	106.81	89.01	89.01

Randy C. Allphin
Contract Administrator

April 25, 2006

Magic Wind
Armand M. Eckert
716-B East 4900 North
Buhl, ID 83316

E-mail Copy: Armand Eckert Armand@safelink.net
Joe Miller joe@mcdevitt-miller.com

Original: US Mail

RE: Magic Wind Park

Dear Mr. Eckert:

We have received and reviewed your proposed Firm Energy Sales Agreement and letter from Mr. Miller, dated April 5, 2006.

Your proposal appears to reflect the pricing mechanisms contained in the recently approved PacifiCorp-Schwendiman agreement - with revisions that increase the prices based on changes proposed by Dr. Don Reading in his comments in the PacifiCorp-Schwendiman proceeding.

Idaho Power believes that the draft contract you have presented fails to acknowledge the role that market prices play in determining the costs Idaho Power is likely to incur if your project fails to perform in accordance with the terms of the agreement. As a result, Idaho Power proposes to utilize the template contract it has signed with numerous QF's similarly situated to your project.

Telephone (208) 388-2614 Fax (208) 433-5163 Rallphin@idahopower.com

The current template Firm Energy Sales agreement that we have previously offered to your project has been accepted by the Idaho Public Utilities Commission (IPUC) as containing terms and conditions that are in compliance with IPUC orders regarding these agreements. This same form of agreement has been recently approved by the IPUC for numerous QF developments, including wind projects.

In previous conversations and e-mails we had completed the details to be contained within a QF agreement for the Magic Wind Park and supplied you with a copy for your review. Attached is an additional copy for your review. If you desire to move your project forward to meet the timelines you have identified, please let me know and I will expeditiously prepare the enclosed agreement for signatures by both parties.

If you have any questions please contact me at your convenience.

Very truly yours,

Randy C. Allphin

Randy C. Allphin
Idaho Power Company
Contract Administrator

Cc: (e-mail) Bart Kline (IPCo)
Karl Bokenkamp (IPCo)
Scott Woodbury (IPUC)
Rick Sterling (IPUC)

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