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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO INCREASE THE PUBLISHED RATE ELIGIBILITY CAP FOR WIND-POWERED SMALL POWER PRODUCTION FACILITIES; AND **TO ELIMINATE THE 90%/110% PERFORMANCE BAND FOR WIND-POWERED SMALL POWER PRODUCTION FACILITIES.**	**CASE NO. IPC-E-07-3** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Scott Woodbury, Deputy Attorney General, and in response to the Notice of Modified Procedure and Notice of Comment/Protest Deadline issued on August 22, 2007, submits the following comments.

BACKGROUND

On February 6, 2007, Idaho Power Company (Idaho Power; Company) filed a Petition with the Idaho Public Utilities Commission (Commission) proposing a $10.72 per MWh wind integration adjustment or reduction to published avoided cost rates. In support of its proposal, the

Company submitted its recently completed Wind Integration Study. The Company requested a Commission Order:

1. Raising the cap on entitlement to published avoided cost rates for intermittent wind-powered small power production facilities that are qualifying facilities (QFs) under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) from the current level of 100 kW to 10 aMW per month; and

2. Authorizing Idaho Power to purchase state-of-the-art wind forecasting services that will provide the Company with forecasts of wind conditions in those geographic areas where the Company's wind generation resources are located. It is Idaho Power's proposal that the Order should further provide that wind-powered QFs will reimburse the Company for their share of the cost of the wind forecasting service; and

3. Authorizing Idaho Power to require the inclusion of a Mechanical Availability Guarantee (MAG) in all new contracts to purchase energy from wind-powered QFs; and

4. In conjunction with the Commission's approval of paragraphs 1, 2 and 3 above, the Company proposes to eliminate the requirement that the 90%/110% performance band be included in new contracts for energy purchases from intermittent wind-powered QFs.

A Notice of Petition and Notice of Preliminary Procedure was issued in Case No. IPC-E-07-3 on February 16, 2007. As a matter of preliminary procedure and prior to any procedural scheduling by the Commission, Idaho Power on March 15, 2007, hosted the first public workshop in Case No. IPC-E-07-3. Pursuant to Notice, a second public workshop was held on June 20, 2007.

Based on additional analysis conducted in response to suggestions made during the public workshops, the Company recomputed its wind integration cost. In response to subsequent production requests, Idaho Power proposed that a wind integration adjustment of $7.92 per MWh be applied to its published avoided cost rates. (Reference Idaho Power response to Production Request No. 3 of Renewable Northwest Project and the NW Energy Coalition).

On July 31 and August 10, 2007, Commission Staff sponsored joint settlement workshops in Case Nos. IPC-E-07-3 (Idaho Power), PAC-E-07-7 (PacifiCorp), and AVU-E-07-2 (Avista) to explore whether parties of record could agree to a common generic wind integration adjustment to published rates. IDAPA 31.01.01.272-276. The parties were unable to reach settlement during these workshops.

On October 1, 2007, however, several weeks after the unsuccessful settlement workshops, Renewable Northwest Project and Northwest Energy Coalition (together, "RNP") submitted a Settlement Stipulation signed by it; Idaho Power; and Idaho Windfarms, LLC. The following comments are submitted in support of the Settlement Stipulation. Similar Settlement Stipulations have been submitted concurrently in cases for Avista (AVU-E-07-2) and PacifiCorp (PAC-E-07-7); consequently, Staff's Comments address the Stipulations reached in those cases as well due to the parallel issues in the three cases.

ANALYSIS

Although there are several secondary issues in this case (90/110 performance band, mechanical availability guarantee, wind forecasting) the primary issue is wind integration costs. To assist in determining its wind integration costs, Idaho Power hired EnerNex, arguably the leading U.S. consulting firm in the area of wind integration studies, and Wind Logics, a leading consultant in the area of wind simulation studies. These consultants provided valuable expertise and experience that supplemented the work of Idaho Power's own staff.

Wind integration studies are rather new, and the techniques for modeling wind and conducting wind integration studies are rapidly evolving. Prior to Idaho Power's study, other studies have been done around the U.S. and in Europe. Comparisons are frequently made between various wind integration studies. Sometimes those comparisons are made simply to show how wind integration costs vary between different electrical systems. Other times comparisons are used to judge the reasonableness of study results, sometimes implying that studies showing costs far outside of the range of other studies must somehow be inferior or inaccurate.

Wind integration costs differ from one system to the next just as electric rates differ between systems. Direct comparisons between integration costs for various utilities are often invalid unless they recognize differences in generation fleets, resources available to integrate wind, the size and resources in the utility's control area, the structure of the real-time market, and most importantly, the difference in value of generation that is moved from on-peak to off-peak times, both on a daily and a seasonal basis to integrate wind.

For example, it is not intuitive that integration costs in a mostly hydro-based system will be higher than costs in a system where gas is used as the primary marginal resource. The costs of wind integration, however, are driven not so much by the costs of the dispatchable resource used for integration, but are instead driven more by the difference in cost between the dispatchable resource and the market price at the time integration takes place. In a hydro-based system, wind integration is primarily achieved by moving extremely low cost hydro generation from hours when it is most valuable to hours when it is least valuable. In a thermal based system where gas is primarily used for integration, there is much less "opportunity cost" in shifting gas-fired generation from high value hours to low value hours.

The studies done by Idaho Power and Avista relied on the best available analysis tools and expertise, and, Staff believes, are as credible as any other study done previously in the U.S. While Staff does not believe that other studies are directly comparable to Idaho Power's, Avista's and PacifiCorp's, those other studies do demonstrate that wind integration costs can be lower in systems where there is greater geographic diversity, larger control areas, greater amounts of quickly dispatchable thermal generation, and shorter real-time markets. Other studies can serve to provide indications that integration costs could become less in Idaho if conditions change in the future.

Wind Integration Cost Uncertainty

One thing that is clear from any wind integration study is that wind integration is imprecise and uncertain. Idaho Power, in fact, recognizes this in its Petition in Case No. IPC-E-07-3 wherein it states, "The wind integration study makes it clear that there is still a great deal of uncertainty surrounding the ultimate impact and cost of adding large amounts of wind generation to the Company's resource portfolio." (Petition page 8). Staff agrees. Workshops held to review the results of the Company's integration study highlighted the broad range of possible outcomes that could be achieved by varying the assumptions for numerous variables used within the study.

Part of this imprecision and uncertainty is due to the difficulty of modeling the intermittent nature of the wind, the generation it produces and its effect on the rest of the electrical system. Another reason is the many assumptions that have to be made in the analysis. For example, assumptions have to be made about the magnitude, locations and timing of future wind generation development; wind forecasting effectiveness, geographic diversity of wind resources; size, height and other characteristics of expected wind turbines; reserve requirements; future electric market structures and pricing; resources available to provide reserves; and operating constraints of existing generation plants. Staff believes that reasonable arguments could be made to justify combinations of differences in assumptions that result in widely varying integration costs.

Another thing that is immediately clear from wind integration studies is that wind integration costs vary as conditions change, and are different under different water conditions, electric market conditions, and wind penetration levels. Because conditions are never the same, some type of average wind integration costs must be used to reflect costs over the long term.

It should also be noted that the avoided cost methodology established to produce the published rate for small projects is itself based on a broad range of assumptions designed to produce a proxy, 20-year levelized contract price. It is not an exact science and adjusting that price for integration costs using an assumption driven system model does not appear to be an exact science either.

Wind Integration Costs are Small Compared to Avoided Cost Rates

One of the primary purposes of this proceeding is to determine whether a wind integration adjustment should be applied to published avoided cost rates. Staff believes it is very important to keep the magnitude of an adjustment in perspective, considering the imprecise and uncertain nature of the wind integration studies. The difference between the $7.92 per MWh proposed by Idaho Power in this case and the $5.04 per MWh proposed by PacifiCorp in Case No. PAC-E-07-7 is $2.88 per MWh, a relatively small amount when compared to the utilities' 20-year levelized published avoided cost rate of about $64 per MWh.

Wind Integration Adjustments and 20-Year Power Sales Contracts

Published avoided cost rates are computed for contract lengths up to 20 years. Computation of the avoided cost rates relies on assumptions about capital and O & M costs and forecasted fuel costs that are intended to be representative over the entire 20-year contract period. Once signed, the avoided cost rates in PURPA contracts are not adjusted throughout the term of the contract.

To be consistent, any wind integration adjustment that is applied to avoided cost rates should also reflect a long-term expectation of what those wind integration costs will be over the entire 20-year period, not just what integration costs might happen to be now. Staff expects that wind integration costs are likely to decrease over the 20-year future for a variety or reasons. For example, energy storage technologies involving batteries, compressed air, capacitors, flywheels, and even electric automobiles are likely to advance in the future. New technologies are also bound to emerge. Electric markets are also likely to evolve to better accommodate intermittent generation.

Finally, utility practices will improve as more experience and confidence is gained with wind generation. In fact, in response to production requests, Idaho Power stated, "Idaho Power has acknowledged that as experience is gained in operating its system with greater amounts of wind generation and potential cooperative agreements between control areas are developed, a future analysis of the impact of wind generation may indicate a lower cost of integration." (Reference Idaho Power response to Request for Production No. 2 of the Renewable Northwest Project and NW Energy Coalition).

Some of the utilities' wind integration studies anticipate changes in geographic diversity and transitions in electric market structures, but it is nearly impossible to envision all of the changes that could take place over the next 20 years. In the same way that avoided cost rates are a long-term estimate, wind integration costs must also be considered over the long term. Because not all future changes likely to affect wind integration costs can be known with certainty now, Staff believes some degree of speculation is required.

Idaho Power's Wind Integration Study

As stated previously, Idaho Power utilized the expertise and experience of EnerNex and Wind Logics to assist in completing its wind integration study. Idaho Power's study has been subject to considerable peer review from the Northwest Wind Integration Plan members and others. It has also been the focus of most of the intervenors in this case because its wind integration study results were initially the highest of the three utilities and because there seems to be the most interest in siting projects in Idaho Power's service territory.

Idaho Power has indicated that geographic diversity of wind, transmission constraints, hourly market structure and limited resources to provide reserves are factors that increase its wind integration costs above those found in other areas of the country. In its Petition, the Company proposed a fixed rate adjustment of $10.72 per MWh. This was later reduced to $7.92 per MWh after additional studies and analyses incorporating acceptable modification of study assumptions were completed during the public and peer review process. Costs were reduced even further to $5.88 per MWh based on an assumption that the Company's share of the coal-fired Bridger plant could be used for down-regulation. Idaho Power dismisses this possibility for now, however, because it does not believe that the Bridger plant could realistically be operated in the manner assumed by the studies.

Avista's Wind Integration Study

Like Idaho Power, Avista also hired EnerNex to assist with portions of its study; however, Avista performed the majority of its analysis using its own staff. Avista's study has been subject to considerable peer review, although its study has received less scrutiny than Idaho Power's, primarily, in Staff's opinion, because Avista's wind integration costs were below Idaho Power's initial results and because there is less interest from wind developers in siting projects in Avista's service territory.

Avista proposed a wind integration adjustment of 12 percent of published avoided cost rates, which equated to $7.57 per MWh on a levelized basis for a 20-year contract. If some type of outside firming service is purchased and an hour-ahead firm product is delivered to Avista by the wind project, the Company proposed that the wind integration adjustment be reduced by half.

PacifiCorp's Wind Integration Study

PacifiCorp proposed a wind integration adjustment of $5.04 per MWh. The adjustment is based on studies conducted initially by the Company's own staff as part of the development of its 2004 Integrated Resource Plan. Wind integration costs have been updated to $5.10 its 2007 IRP, which is still pending Commission acceptance. Because PacifiCorp conducted its studies much earlier than either Idaho Power or Avista, the analysis lacks some of the sophistication of the later studies and may not fully account for all components of wind integration costs. In addition, the analysis may be a bit more outdated than others. Because PacifiCorp's study was just one small element of the much larger exercise of developing an Integrated Resource Plan (IRP), the wind integration study has been subjected to far less scrutiny and peer review than either of the other two utilities' studies. PacifiCorp has never prepared a report presenting the details and results of its wind integration study. Instead, a description of its study and results is contained in a mere 2½-page appendix of its IRP. With such minimal documentation of PacifiCorp's study, it is difficult to judge its accuracy or to contrast its results with those of Idaho Power and Avista.

Wind Integration Adjustment to Avoided Cost Rates

Based on the uncertainty in assumptions used in the integration studies and the impact that uncertainty has on estimated adjustment to published rates, and based on the fact that wind integration costs must be estimated 20 years into the future, Staff believes it is reasonable to accept the wind integration charges included in the Settlement Stipulation as reasonable approximations of wind integration costs going forward. Wind integration costs as proposed in the Stipulation, as a percentage of avoided cost rates, are as follows:

Idaho Power

Amount of wind online	Integration cost adjustment as a percentage of avoided cost rates
0 to 300 MW	7%
301 to 500 MW	8%
501 MW and above	9%

Avista

Amount of wind online	Integration cost adjustment as a percentage of avoided cost rates
0 to 199 MW	7%
200 to 299 MW	8%
300 MW and above	9%

PacifiCorp

A wind integration cost adjustment of $5.04 for all new PURPA wind projects.

For Idaho Power, seven percent of current published avoided cost rates is $4.37 for a 20-year contract with a 2007 online date. At nine percent, the integration cost would be $5.62 based on current avoided cost rates. Under the terms of the Stipulation, the amount of the integration charge would be capped at $6.50 so that it could not exceed this amount as avoided cost rates increase in the future.

Staff believes the proposed wind integration adjustments balance the utility-specific attributes identified in the integration studies of both Idaho Power and Avista while recognizing that neither of these utilities currently has the necessary amount of wind resources online to justify the level of wind integration costs reported in the studies and proposed initially by the companies. Staff also believes that the larger service territory of PacifiCorp, which reduces the limitations of available resources, transmission and wind diversity in conjunction with greater operation and forecasting experience, justifies a somewhat smaller integration cost adjustment.

The proposed integration costs, because they are significantly below the values determined in the utilities' wind integration studies, acknowledge that over time integration costs should decrease as markets mature, geographic diversity improves, technology advances, and experience is gained in operation and forecasting. Staff believes the proposed integration costs are a reasonable long-term estimate over the typical 20-year PURPA contract term. The Stipulation also recognizes, however, that integration costs will increase as greater amounts of wind come online, a result that was apparent from the studies of both Idaho Power and Avista. Periodic reviews as provided for in the Stipulation will provide opportunities to revise the adjustment if downward and upward pressures on wind integration costs get out of balance.

Wind Forecasting

All parties in this case seem to agree that forecasting can be valuable and that it can help to reduce integration costs. The disagreement lies in who should bear the cost of wind forecasting. The utilities contend that forecasting costs are the responsibility of the project owner, because if not for the project, there would be no need for the forecasting. Project owners contend that if they are charged with the cost of forecasting, then the wind integration discount applied by the utility should be less due to the benefits of forecasting in lowering integration costs. Still others contend that the utilities and the project owners both benefit from forecasting and conclude that costs should be shared in proportion to the value of benefits received by each.

Staff supports the rationale that both parties benefit from forecasting and therefore should share the costs. Furthermore, Staff acknowledges that the costs of forecasting are relatively small. Staff supports the terms of the Settlement Stipulation under which forecasting costs will be shared equally, subject to a cap on the wind QF's potential liability for such costs set at 0.1 percent of project revenues.

Mechanical Availability Guarantee

Both the wind project developers and the utilities in this case support a requirement for a Mechanical Availability Guarantee (MAG). Under a MAG, projects would have to insure that they are mechanically available to operate some specified percentage of time in order to be eligible for discounted published avoided cost rates. Staff contends that project owners already have very strong incentive to insure mechanical availability—if equipment is not mechanically available, there can be no generation, thus no revenue. Nevertheless, Staff supports the MAG requirement as proposed in the Stipulation.

The MAG concept seems simple, but Staff believes that application of the MAG requirement in practice is more complicated. First, enforcement of the MAG will be difficult. The only real proof a turbine was available to operate during a month is whether it in fact operated. When the wind is not blowing, or is blowing at less than cut-in speed or more than cut-out speed there is no way to confirm mechanical availability other than the word of the developer. To make enforcement easier and consistent between utilities, Staff proposes that these hours not be counted for purposes of computing mechanical availability. Confirmation of availability when there is enough wind to operate requires that accurate hourly wind speed data be collected, and that computations be made using this data and corresponding electrical generation data. Multiple turbines (which nearly all projects will have) complicate the computation of availability because some turbines may be mechanically available and others not. Staff recommends that if a MAG requirement is adopted, that the MAG requirement be 85 percent of all hours during the month when wind speed is between the turbines' cut-in and cut-out speed, and that electrical output be measured on a project basis rather than an individual turbine basis.

Periodic Updates to Wind Integration Costs

If the Commission adopts an adjustment to published avoided cost rates to account for wind integration costs, Staff believes that such an adjustment should be subject to periodic review. Each of the utilities' wind integration studies have shown that integration costs escalate as penetration levels increase. At the same time, however, wind integration costs will likely decrease over time as utilities gain more experience integrating wind, as forecasting improves, as ancillary services markets evolve and as technology advances. Whether the factors causing integration costs to increase completely offset the factors causing integration costs to decrease remains to be seen. Moreover, the study of wind integration costs itself is evolving. With each new integration study that is conducted, new knowledge is gained and new tools developed for better assessing wind integration costs. For all of these reasons, Staff believes that wind integration adjustments established today will not necessarily be the appropriate amounts for contracts that may be signed several years from now.

One option is to simply escalate wind integration costs as wind penetration levels increase in accordance with the results of each utility's wind integration study. This approach ignores the likelihood, however, that wind integration technology and practices will improve over time. As a result, Staff does not recommend this approach.

A much better approach, Staff believes, is to permit periodic reviews of wind integration costs in the same way that the variables used to compute avoided cost rates are subject to periodic review. Under the avoided cost methodology, parties can petition the Commission at any time to open a docket to review and update variables if those variables are believed to be outdated or inaccurate. This approach recognizes that each utility might have a different integration cost, but synchronizes the timing of review of all three utilities' integration costs so that interested parties can coordinate their efforts and so that appropriate comparisons can be made between utilities.

Under the terms of the Settlement Stipulation, Idaho Power will convene an informal wind integration working group which will meet at least two times during 2008 to discuss Idaho Power's wind integration study and new data related to wind integration costs. In addition, Idaho Power will review wind integration costs as part of its integrated resource planning process in the same way that costs for other generating resources are included. These provisions will help to insure that wind integration costs are regularly scrutinized, and will alert parties about when to possibly make application to the Commission to open a docket for the purpose of updating avoided cost computation variables, including wind integration adjustments.

Cap on Entitlement to Published Rates

All three utilities have proposed that some sort of cap on entitlement to published rates be imposed once a specified wind penetration level is reached within each utility's respective service territory. In most cases, the proposed "cap" is simply a requirement that wind integration costs be reevaluated at specified penetration levels, although this is not completely clear or consistent in each utility's application. For purposes of clarification, Staff assumes that each utility's proposal is a requirement to reexamine integration costs at specified intervals, not a proposal that the utility be excused from its obligation under PURPA to purchase additional wind generation after certain wind penetration levels have been reached. Excusing utilities from their obligations under PURPA is not something the Commission can do, Staff believes, regardless of the quantity of wind offered for purchase or of the utility's cost or difficulty in integrating it.

Elimination of 90/110 Performance Band

Each of the utilities proposes that the 90/110 percent performance band requirement be eliminated if a wind integration discount and the other proposed contract provisions for wind are adopted. The original purpose of 90/110 percent performance requirement, Staff believes, was to insure that projects provided a degree of firmness sufficient to make them reasonably comparable to other utility and market resources normally priced at what have historically been known as "firm energy" rates. Prior to this time, all wind generation was assumed to be non-firm and therefore eligible only for market-based non-firm energy prices. By requiring a degree of predictability in order to qualify for firm energy rates, utilities attempted to better match the prices it was required to pay with more standard industry definitions of the product it received.

The adoption of a wind integration adjustment, a MAG, and wind forecasting really do nothing to increase the firmness of wind generation on a long-term basis. There is still no assurance, for example, that the wind will be blowing on a specific day or at a specific time in the future when the utility most needs the generation. These measures do, however, financially account for wind's intermittency on a short-term basis, and are, Staff believes, an acceptable substitute for the 90/110 percent performance band requirement.

With implementation of a reasonable integration cost adjustment for wind, a measured approach to wind forecasting and adoption of a verifiable MAG, Staff supports elimination of the 90/110-performance guarantee as discussed in the Settlement Stipulation. For non-wind resource types not subject to the integration adjustment, Staff recommends that the 90/110 requirement be retained.

Availability of Terms From This Case to Existing Contracts

The Settlement Stipulation proposes that terms accepted by the Commission in this case as required conditions for new contracts be available to existing wind contracts should they wish to be renegotiated. For example, the Stipulation suggests that existing contract be able to be renegotiated to remove the 90/110 performance requirement and impose a MAG requirement in exchange for avoided cost rates discounted by a wind integration adjustment.

Staff has no objection to renegotiation of existing contracts, provided that <u>all</u> of the terms of the Stipulation are included in the amended contracts (i.e., elimination of the 90/110 provision, inclusion of the 85% MAG requirement, sharing of forecasting costs, and application of an integration adjustment). In addition, Staff believes that the wind integration adjustment must be applied to the rates contained in the original contract and not to whatever avoided cost rates may be in effect at the time the contract is renegotiated.

RECOMMENDATIONS

Staff recommends that the cap on entitlement to published avoided cost rates for intermittent wind-powered small power production facilities that are qualifying facilities (QFs) under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) be raised from the current level of 100 kW to 10 aMW per month. Staff further recommends that the Commission accept the Idaho Power Settlement Stipulation containing the following:

- An integration cost adjustment as shown below should be applied to the published avoided cost rates of Idaho Power for all intermittent PURPA resources, subject to a cap of $6.50 per MWh.

Amount of wind online	Integration cost adjustment as a percentage of avoided cost rates
0 to 300 MW	7%
301 to 500 MW	8%
501 MW and above	9%

- The 90/110 percent performance band requirement should be eliminated for all wind resources.
- A mechanical availability guarantee of 85 percent should be required for all new contracts.
- The costs for wind forecasting services, where shown to be cost effective, should be shared equally between the utility and the wind project owner, with a cap on the wind project's potential liability for forecasting costs set at 0.1 percent of annual project revenues.
- Wind integration costs should be subject to periodic review through informal working groups and through the IRP process, and possible future updates to wind integration costs should be made as part of a docketed case to review all variables used to compute avoided cost rates.
- There should be no cap on entitlement to published avoided cost rates.
- Holders of existing contracts for wind projects should be permitted to renegotiate those contracts, provided that all of the terms and conditions included in the Stipulation are

adopted and that the rates in the contract are based on those that were in place at the time of the original contract signature.

Respectfully submitted this 5th day of October 2007.

Scott D. Woodbury

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 5TH DAY OF OCTOBER 2007, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-07-03, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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