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**BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

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| In the Matter of the Application of PacifiCorp for Approval of an IRP Based Avoided Cost Methodology for QF Projects Larger than 3 Megawatts | Docket No. 03-035-14 |

**PREFILED TESTIMONY OF TRACY LIVINGSTON**

Wasatch Wind hereby submits the Prefiled Testimony of Tracy Livingston in this docket.

DATED this 29th day of July, 2005.

Tracy Livingston

/s/________________________
Tracy Livingston
Representing Wasatch Wind

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email or mail this 29th day of July, 2005, to the following:

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**PREFILED TESTIMONY**

**Of**

**TRACY LIVINGSTON**

On behalf of Wasatch Wind

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In the Matter of the Application of PacifiCorp for Approval of an IRP Based Avoided Cost Methodology for QF Projects Larger than 3 Megawatts

Docket No. 03-035-14

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July 29, 2005

**<u>BACKGROUND</u>**

**Q. Please state your name and occupation.**

A. My name is Tracy Livingson. I am the Manager of Wasatch Wind, LLC, a wind project development company serving the West and CEO of Wind Tower Composites, LLC a technology engineering firm funded by the US Department of Energy. Both companies are located at 357 W 910 S, Unit A, Heber City, UT 84032

**Q. On whose behalf are you filing testimony in this Docket?**

A. Wasatch Wind, LLC

**Q. Have you submitted testimony to this Commission before?**

A. No.

**Q. Could you describe Wasatch Wind and your project without revealing any propriety information.**

A. Yes. I will try. WW has been monitoring wind resources at the mouth of Spanish Fork Canyon in the industrial zone of Spanish Fork City for the past 8 months for the purpose of building, owning, and operating a wind farm of 14.7 MW. Measuring towers at the site consist of an 83m tall unit with anemometers at 5 levels and another 50m tower with three levels. In addition to the recent data, 2.5 years of historical wind data has been evaluated from two towers between the two mentioned towers at 10m and 30m heights. Thus, we have a robust wind resource data set that gives us clear metrics and hourly based power performance predictions and statistical output probabilities of the proposed wind turbines. The project has recently received a zoning change approval by Spanish Fork City and is ready to file an interconnect agreement with the Company as soon as "FERC Docket No. RM02-12-000; Order No. 2006" regarding interconnect procedures has been formally adopted by the Company and assuming QF proceedings result in a rate structure commensurate with a reasonable return on investment for the project.

## SUMMARY OF TESTIMONY

**Q: What is the purpose of your testimony in these dockets?**

A: I will provide some background into the Utah wind development market and identify some of the barriers that I perceive exist that are inhibiting renewable resource development. First, this is a particular market in that wind developers and in fact all QFs can not sell directly to the consumer, we must go through a middleman, i.e., the local regulated utility or to a municipal utility. We can sell on the wholesale market but not to the final consumer. This is a barrier that obviously is beyond the scope of this docket, but put our issues in the right perspective, particularly in light of the fact that there are customers that are willing and able to pay more for renewable power. The success of PacifiCorp's Blue Sky program clearly illustrates this fact. I will try to explain my perception of the problems in dealing with a utility and some of the barriers that we have encountered. In addition, I will illustrate that all wind resources are not created equal and in fact that there are significant differences in the Spanish Fork project and the other wind resources that the Company has used in the determination for the value of capacity credit for wind farms. I will illustrate inconsistencies in recent Company testimony in this regard and make recommendations in regards to capacity payments.

**Q: Could you give a summary of your conclusions and recommendations?**

A:

**Q: Is your project ready for rate negotiations with the Company?**

A: Yes, except the projects implementation will depend on a rate structure that is higher than what is presently employed and being proposed by the Company under Schedule 38. The Spanish Fork project has completed all wind resource monitoring, site approval, turbine selections, cost analysis, and has preliminary financing arranged depending on the outcome of the proceedings.

**Q: Why did you not participate in the 2003 RFP?**

A: Due to the complexity of wind project developments in general and the small size of our project, we were unable to fully anticipate the timeline for site approval to correspond to the IRP's deadline.

**Q: Do you think the present RFP process is the most efficient method to maximize small wind project development?**

A: No. Wind projects have inherently more initial capital at risk than some other traditional forms of generation. This is due to the unqualified characteristics of a potentially windy site. Thus a developer may have upwards of 10 initial sites selected with towers at each and will have negotiated 10 separate land agreements just to qualify one project. Once a viable project is identified, wind developers still have a difficult time determining when a project will be ready to bid into an RFP due to the combination of more typical development characteristics such as local site approval in addition to the wind resource risks. Because of this complexity and the large time span that can occur between RFP's, a wind project may have to wait over 5 years before the opportunity and the RFP deadlines are concurrent. During this time even assuming the site is well qualified, transmission is available, and permitting is obtained, the supply and demand for turbines can squeeze out small projects at worst and at best typically can cause the project price to rise. This is exacerbated due to the boom and bust demand cycles on turbine availability created by the start and stop efforts of the federal production tax credit and the large demands for turbines in states with Renewable Portfolio Standards with more streamlined processes for pricing and development enabling developers in those states to plan appropriately before deadlines expire. These combinations mean that development of projects in Utah with a long time horizon because of the wait to bid into an RFP create unacceptable risk. Thus many smaller projects will remain undeveloped and even initial wind resource development will continue to be suppressed unless an attractive alternative is available.

**Q: Assuming that shorter time lines for RFP's where provided would this reduce the risk?**

A: Not with the present history of the Company showing limited action in awarding wind contracts. The Company has stated that 1400 MW's of projects would be integrated into the system according to the 2004 IRP and the last RFP. To date, nearly three years later, only one project in Idaho has been awarded and none in Utah. Most small wind QF's therefore cannot presently justify the upfront risk capital when looking to the Company for RFP based strategies.

**Q: Do you believe the present 3 to 99 MW QF rate structure is the appropriate mechanism for small wind farm development?**

A: No. The wind resource at the mouth of Spanish Fork Canyon based on my three years of extensive comparison of wind resources at other sites in Utah is the best in the state and is comparable to several sites in Wyoming. The capacity factor is greater than the Evanston Wind Farm that we understand is 32% annualized. When adjusted to on peak vs off peak, the Spanish Fork project has slightly more off peak hours but offsets this by greater than 40% capacity factor in the Summer months (especially in the morning hours) and slightly less in the Winter months. The site also has the benefit of easy access, no need for road work, and adjacent substation. All in all, our assessment based on extensive financial analysis of the site metrics in comparison to other projects throughout Utah and Idaho give us a unique understanding of the cost structure of projects that would either bid into a 100MW+ RFP or Schedule 38. Based on this evaluation, neither this project nor any other QF wind project will be developable under the Companies proposed Schedule 38 pricing.

**Q: What pricing do you believe will make QF wind projects possible?**

A: Based on our knowledge of the wind resources in Utah and Idaho, and the present requirement for independent financial institutions involved in wind farm financial investments across the country to achieve an un-leveraged after tax IRR of 9% minimum, for a typical 10 to 20 MW wind farm with a net capacity factor of 32% and a 50/50 on peak vs off peak energy balance as typical for the intermountain region, the levelized rate structure would need to be $0.0565 per kwh blended for capacity credit and energy costs for a 20 year contract assuming the project retains the green tags valued at $.002 per kwh. Adding integration costs as applied from the IRP of $4.64 per MWh gives a total of $0.0611. This is near the rate structure for wind projects in the 2004 IRP and above the proposed schedule 38 QF rates. We used our actual project costs of $1995 per kw as a conservative value plus $4.52 per kw per year O and M costs as mandated by the turbine manufacturer that also includes recently verified additional expenses including insurance, property taxes, leaseholder payments, admin costs, and spare parts contingencies. We used a baseline financial model that is a well vetted and considers all tax advantages and state tax credit incentives and is used by several developers.

**Q: What do you believe is the pricing in the RFP and in the IRP?**

A; The Company has bids in hand from the RFP and has recently asked the 2003 participants to “refresh” their bids. We believe that all the projects will reflect a cost that will be equal to or exceed $0.0611 plus an assumed value for the green tags at $0.002 for a total of $0.0631 per kwh. Thus we expect that the RFP bids would be somewhere between $0.0631 and the IRP estimates in the mid six cent range based on calculations of the 2004 IRP inputs.

**Q: This is higher than the Companies proposal under Schedule 38 so how do you justify this rate?**

A: Considering the Company has already estimated the costs of wind farms into the IRP at a higher rate, and according to their own models has determined that 1400 MW of wind at these rates is the optimal portfolio mix, and due to the fact that the RFP bids are most likely near this higher rate, then small QF projects should be evaluated according to the proxy method using incremental wind costs from the IRP and from the large QF bid prices.

**Q: Do you believe that the bidding process to obtain rates for 100 MW or larger projects and the determination of rates under schedule 38 for 3 to 99 MW projects are equitable.**

A: No. A large disparity in pricing exists between the two programs as illustrated in our previous answers. Further, under recent testimony of Griswold Docket No. 03-035-14, May 2005 he states the position of the Company as follows:

"PacifiCorp would not be required to accept offers for QF capacity that were made outside of the bidding process, or from QFs that were not selected through the competitive bidding process. However, PacifiCorp would be required to accept offers for QF energy at prices determined using the GRID model, as described in Mr. Duvall's testimony." Because of the low avoided cost prices that are determined when the GRID model is used and the much larger prices under the 100 MW bid program, and the exclusion of a 3 to 99 MW project to participate in this bid process, the result is inequality between the QF's based solely on an artificial size constraint.

**Q: Do you feel the present avoided cost price methodology is flawed in regards to wind projects?**

A: Yes. We are not experts in the modeling that the Company uses to determine avoided costs but we are familiar with the market for wind costs and wind resources in the region. We only need to look at how other states evaluate wind prices to see that the present model is overly complex and inaccurate. For example, in studies of the Excel system in Minnesota the wind integration and capacity values were extensively evaluated by EnerEx Corp.[1] In that study, the distribution of geographically dispersed wind farms accessing non-concurrent wind regimes improved the capacity value of the system. It appears that based on the Company's suggested fixed capacity credit proposal of 20% implies that the Company did not analyze the value of dispersion. If they had evaluated dispersion, then we would have expected a proposal with this factor integrated into the pricing. Further, Idaho uses yet a different methodology for determining avoided costs, this method yields a cost for wind projects that are on average $18

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1 EnerNex Corp., et al. "Xcel Energy and the Minnesota Department of Commerce." Wind Integration Study- Final Report. September 28, 2004, p.66.

per MWh higher than the Utah Grid model; this in a state where the Company also does business with natural gas resources, and plant and capital costs that should be similar to Utah's. Either one of the states is wrong in the methodology, or Idaho's assumptions are aggressive and yield a higher price or Utah's model is overly conservative. We suspect the truth is in the middle but nevertheless this illustrates that any "calculated" model will result in inaccuracies and is strongly driven by assumptions that also may be inaccurate.

**Q: Do you believe there are other flaws in the avoided cost methodology for wind projects?**

A: Yes, namely the proposal by the Company to pay 20% capacity credit for all wind projects is inconsistent with recent testimony. In Griswold Docket No. 03-035-14, May 2005, Mr. Griswold states, "…wind speed and duration are characteristics which directly impact site generation and the capacity factor of a particular wind site. Second, seasonal and time-of-day patterns determine wind contribution during peak hours. Third, the composition of the existing resource mix as well as volatility in system loads and resources affect how wind's capacity contributes to the Company's system." We also believe this to be true. So it seems odd that the Company recognizes that capacity value is a function of a particular site and yet groups all wind farms into one average category and recommends a fixed payment structure. In order to prove that sites can be vastly different and their capacity values diverse we evaluated the wind and power distribution on a hourly, monthly and seasonal basis for a public domain wind site in Medicine Bow, Wyoming against the Spanish Fork Wind site. We expected the WY site would be subject to macro wind conditions that can vary greatly from day to day as a result of local convection and frontal activity, jet stream location, and other broad based weather patterns while the Utah site is a diurnal flow relatively insensitive to broad based weather phenomena. This was determined to be the case. For example, the coefficient of variation of the mean wind speeds in the summer and winter where analyzed. This CV is the % of time that the wind speed will be within 32% of the mean wind speed at any given time. If the CV is 0% that means that the power output is at the mean 100% of the time and is so predictable that the capacity value is also 100% for that time period. Anything more than 0% variability should have a proportionality adjustment for capacity value. So the larger the CV the more variable the wind resource and the less valuable the credit in relative terms. For the WY site the CV is 70% during summer and winter during on peak hours when the turbines are generating which reflects a large variance in wind resource. For the Utah site the CV is 30% in the Summer and 52% in the winter reflecting a much lower variance and an indicator that the Utah site has a much higher capacity value for those on-peak hours. Both sites also have different capacity factors ie 36% for WY and 32% for Utah; thus the adjustment of variance as it relates to capacity credit is a function of both factors too. Also, the distribution of total annual energy allocation is vastly different for the two sites: On a seasonal basis, the Wyoming site outputs 43% of total annual energy output in the winter and 25% in the Summer while the Spanish Fork site is just the opposite with 31% in the Winter and 40% in the Summer. The WY site has a daily distribution that slightly peaks in the afternoon with an hourly average capacity factor of 55% from 11 am to 6 pm peak hours in the winter but also has a large 59% CV reflecting large variability while the Utah site has an average 67% capacity factor during 3 on-peak morning hours in the summer with a very narrow CV of 25%. Thus the Utah site could be depended on more for capacity in those few hours than the WY site in the winter afternoon. We could go on and on with statistical differences but the point that sites can be vastly different in capacity value is made and therefore the pricing for this value should be on a case by case basis if using the Schedule 38 avoided cost methodologies.

Q. **Do you believe integration costs are consistent with system wide actual capacity?**

A. No. Presently integration costs are assumed based on implementation of wind energy on a massive scale. While these costs may be appropriate at this level, they are nearly zero in the early implementation of wind resources, especially for a small QF project when wind resources are below 100 MW. This is known merely by looking at other well respected studies of this issue at different levels of integration as well as the integration costs for lower levels in the 2003 IRP. This cost is also a function of wind diversity as illustrated by the Excel energy study in

Minnesota.

Q. **Do you have suggestions on how to determine the pricing for small QF's?**

A. Yes. We again turn to the testimony of Griswold Docket No. 03-035-14, May 2005 where he states, "a competitive bidding approach would provide the Commission, the customers, the Company and QF developers with the best available determination of the Company's "avoided costs" and, as a result, would best meet the ratepayer indifference standard." We also believe this to be true. Therefore, we suggest that the pricing should be determined for small QF's by using the higher of 1)the rate as assumed in the most recent IRP model and 2) an average of the three most viable, lowest cost, large QF bidders in the most recent RFP of which contracts have been awarded for the same type of resource. If no contracts have been issued then the IRP assumptions on prices would prevail. Agreed upon adjustments can then be made as appropriate for other costs unique to each site such as capacity credit and proximity to loads.

Q. **Wouldn't this price methodology disrupt the large QF bidding process and encourage gaming by the large QF bidders to break up a project and participate in a non-bid contract?**

A. Not if capacity caps and project sizes are imposed. For example, we suggest that project sizes from 0 up to 20 MW would be the maximum size that would be eligible for the "rate matching" program. The 20 MW size limit is suggested as this is the same threshold that FERC uses to define a small QF per "Docket No.

RM02-12-000; Order No. 2006" in regards to interconnect size. The cap on the total eligibility for the program could be imposed for each type of generation resource. If the cap is relatively small for each generation type such as 100 MW for wind projects and the same for geothermal, etc, then the larger QF's would not be able to fully implement their total project by breaking it into pieces and thus would continue to participate into the bidding program. Limits could also be imposed on the number of applications in a given time period for a geographic area to further prevent "break up" but are most likely unnecessary.

Q. **What do you suggest for pricing projects between 20 and 100 MW?**

A. These would be eligible to participate into the bidding process as presently defined for the 100 MW and larger projects.

Q. **Why do you believe that this "proxy" method is appropriate?**

A. The method is in line with the direction mandated by PURPA to pay QF's at avoided costs because the implementation of a small QF "avoids" the cost of a similar resource being planned as part of the IRP. This also encourages a more balanced IRP that more closely matches QF projects. It also provides self-correction because if the IRP is too high on costs then small QF's become a larger part of the resources and if too low is corrected by market based bids. Thus IRP price estimates that govern resource allocation are driven lower but corrected by the market as necessary.

Q. **How would bid disclosure effect future bid processes?**

A. Full disclosure at worst should not affect future RFP's and at best should encourage lower prices during the next cycle as all participants are bidding using the same pricing information. Further, with properly structured RFP's the Company should be able to defer future RFP's for a significant period of time, thus discouraging bidders from waiting for the next cycle where previous bid prices are disclosed. In addition, if the RFP process is delayed and market prices have dropped in the interim, more QF projects will be built, thus encouraging the company to begin another RFP to correct the discrepancy.

Q. **What would you suggest is appropriate for the green tag pricing and ownership?**

A. The ownership of green tags should remain with the project owner. This keeps equality across other QF resources that do not produce green tags yet are subject to the the same QF guidelines of "avoided cost". In order to determine final pricing of the project under this new "proxy" method, the green tags should be subtracted from the pricing if the tags are included in the bids or the RFP. The value of this pricing should be determined by what Pacificorp is willing to pay for the tags. The owner would then have the option of including the tags but would not be mandated to give them up.

Q. **Can you summarize your testimony and recommendations?**

A. Yes. Small QF's should be defined as 0 to 20 MW project size and would be eligible to receive pricing based on a combination of IRP pricing and RFP bidding of large QF projects. Large QF's would be defined as larger than 20 MW. This pricing method is consistent with PURPA for determination of avoided cost and is consistent with recent testimony of the Company. Adjustments to pricing for integration costs and capacity payments would reflect the metrics of the project at the time of contract negotiation. Green tags would remain with the developer.

**Q. Does this conclude your testimony?**

A. Yes it does.