The Use of Tall Tower Field Data for Estimating Wind Turbine Power Performance

A. Swift[1], J. Chapman[1], L. Manuel[2], K. Walter[1], R. Slavens[1], S. Morse[1]

Abstract

The ten-minute average wind speed at any reference elevation is a random variable that is typically modeled using a Weibull distribution. At potential wind turbine sites, it is uncommon to have wind measurements available at multiple heights. Then, one usually applies an assumed constant shear exponent (such as 1/7 with a power-law profile) along with the reference wind speed to predict wind speeds at other heights. As the next generation of multi-megawatt wind turbines begins to feature hub-heights at or above 100m, some question may arise to the validity of these traditional approaches.

At Texas Tech University's Wind Science and Engineering (WISE) Research Center, unique data sets are available for the study of power performance for a variety of turbine hub heights. One data acquisition tower is continuously measuring and recording atmospheric conditions at multiple levels up to 200 meters, using a variety of instruments that include *u-v-w* anemometers and instruments providing barometric pressure and temperature data. A second data acquisition tower approximately 100m distance from the 200m tower is continuously measuring and recording wind speed using traditional 3-cup anemometers at 10m and 78m heights above ground level.

The influence of the usual assumptions made in predicting output power, such as extrapolation to different heights assuming some constant shear exponent, can be assessed using the available data. More importantly, the underlying probabilistic description of the wind velocity at different levels can be estimated directly from field measurements. Using available data, this paper will compare power production estimates from actual high-level wind velocity data sets directly to a variety of less omniscient power estimation methods. The WISE tower is a Southern Great Plains site and, as such, might be representative of similar sites throughout the Great Plains.

Methods

The ensuing analysis is valid for a period of Feb. 15, 2005 to Dec. 31, 2005, which is the time period during which the observation record for both towers overlaps. While this time period is not adequate for a thorough estimation of absolute annual energy output, it is adequate for comparing annual energy output estimations from a variety of methods *relative to one another*. Data collected from the first data acquisition tower, the "200m Tower", are 30Hz wind speed data from u-v-w anemometers averaged by default to one-hour increments at the 10, 116, 158, and 200m levels. Data collected from the second data acquisition tower, the "78m Tower", are 10-minute averages at the 10 and 78m levels, which both feature traditional 3-cup anemometers for measuring wind speed. The available measurement heights for both towers are shown in Figure 1 for comparison to a hypothetical wind turbine. Both datasets have been quality-controlled to remove instances of obvious instrument error. However, the quality control routine was purposefully written at a low level of aggression so as not to unwittingly remove any of the unique atmospheric phenomenon that occur on the Southern Plains.

[1] Wind Science and Engineering Research Center, Texas Tech University, Lubbock, TX: www.wind.ttu.edu
[2] Dept. of Civil Engineering, University of Texas, Austin, TX

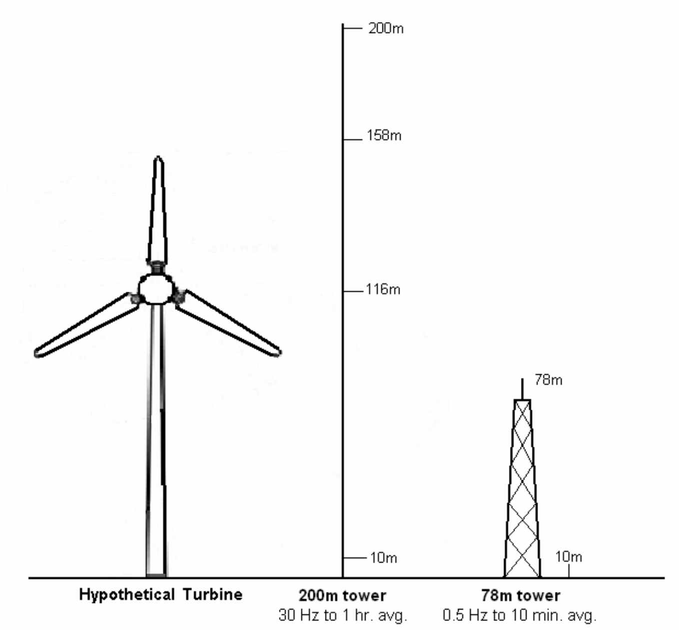

Figure 1. Heights of available wind speed measurements on the TTU WISE 200m and 78m towers. A hypothetical wind turbine is shown for comparison.

Since the site of the data acquisition towers is at relatively high elevation (~1000m), we have included a 15% reduction to the standard GE1.5xle wind turbine power curve for all annual energy output calculations to account for a reduction in air density.

Analysis

The heart of this analysis are annual energy output estimations at a hub height of approximately 100m (116m actual) using a variety of methods that involve varying amounts of site-specific data. As a starting point, time-period averages for the relevant heights of both towers are shown in Table 1. As a check, the time-period average for a third on-site 10-m anemometer (the TTU Reese Mesonet station) is also shown. Since the horizontal separation of the 200m and 78m towers is only several hundred feet, the slight discrepancy in period-average wind speed is likely due to the sporadic absence of data from the 200m data set. Since data outages were seemingly random, their average affect is minor and the ability of the dataset to provide representative wind characteristics is believed to be in tact.

Table 1. Period-averaged wind speeds and power-law shear exponents for available levels of the TTU 200m Tower and 78m tower from Feb. 15, 2005 – Dec. 31, 2005.

	10m ws (m/s)	78m ws (m/s)	10-78m alpha	116m ws (m/s)	10-116 alpha
200m tower	5.07			8.63	0.217
78m tower	4.99	7.95	0.226	8.82 (extrap)	
Reese mesonet	5.02				

The first method of annual energy output estimation, "Method 1", assumes that the user has only the average 10m wind speed for a site of interest. In this case, we will use the 10m average wind speed from the 200m Tower, 5.07m/s. Now, an extrapolation to hub height (116m) is made using the power law with a commonly-assumed 1/7 shear exponent. From this new hub-height estimation of average wind speed (7.20m/s) a Rayleigh distribution is created to provide some representation of the wind speed frequency distribution. These probabilities are each then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is then the estimate of annual energy output from Method 1, which in this case is 4767 MWh.

The second method of annual energy output estimation, "Method 2", assumes that the user knows the average 10m wind speed *and* the measured frequency distribution for a site of interest. In this case, we will use the actual 10m wind speed frequency distribution from the 200m Tower. Now, since extrapolation of the bin-specific probabilities themselves is impossible, an extrapolation to hub height (116m) is performed on each of *the wind speed bin values themselves* using the power law with a 1/7 shear exponent. This essentially means that the measured probability at each 10m wind speed bin will occur at hub-height at a new, extrapolated, higher-velocity wind speed bin. These probabilities are then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each *new* bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is then the estimate of annual energy output from Method 2, which is 5366 MWh.

The third method of annual energy output estimation, "Method 3", assumes that the user has only the average 10m wind speed and the period-averaged power-law exponent to some higher height for a site of interest. In this case, we will use the 10m average wind speed from the 200m Tower, 5.07m/s, and the period-averaged shear exponent ("alpha") from the 10-78m layer on the adjacent 78m tower, 0.226. Now, an extrapolation to hub height (116m) is made from 10m using the power law with the period-averaged shear exponent 0.226. From this new hub-height estimation of average wind speed (8.82m/s) a Rayleigh distribution is created to provide some representation of the wind speed frequency distribution. These probabilities are then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is then the estimate of annual energy output from Method 3, which in this case is 6439 MWh.

The fourth and final method of annual energy output estimation, “Method 4”, assumes that the user has the time-history data from both 10m and some higher height for a site of interest. In this case, we will use the 10m and 78m wind speed records from the 78m Tower. For each 10-minute interval, a 10-78m shear exponent is calculated, and that shear exponent is used to extrapolate the 78m wind speed to 116m. This method differs from Method 3 by not forcing the probability distribution into a Rayleigh shape. These probabilities are then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is then the estimate of annual energy output from Method 4, which in this case is 7331 MWh.

As a baseline comparison for each of these estimation methods, the “Baseline” calculation uses a frequency distribution obtained from the actual time-history data from 116m from the 200m Tower. These probabilities are then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is then the “correct” estimate of annual energy output, 7191 MWh. A summary of these methods and their respective errors appears in Table 2.

Table 2. Annual Energy Output Estimation Method Summary.

Method	**Required Data**	**AEO Estimate (Mwh)**	**% Error**
1	10m avg. ws	4767	33.7%
2	full 10m data set	5366	25.4%
3	10m avg. ws, avg. power law exponent	6439	10.5%
4	full 10m and higher-height data sets	7331	1.9%
Baseline	full hub-height data set	**7191**	0.0%

Interestingly, all estimation methods except for Method 4 under assess the annual energy output by 10% or more. In the worst case, the error is as high as 33%. Also, while Method 4 is the most rigorous method and features the smallest error, it is the only method to *over*-estimate the annual energy output of the hypothetical turbine. Graphically, these methods are compared in Figures 2 and 3.

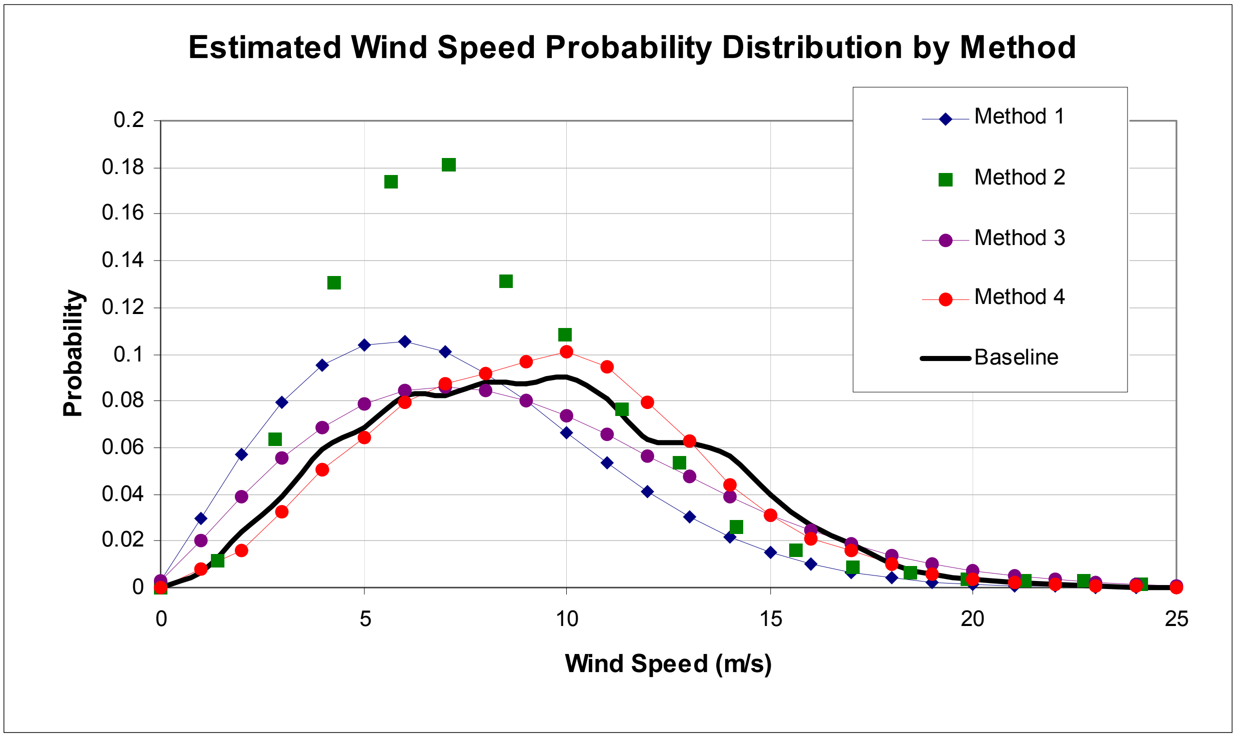

Figure 2. Wind speed frequency distributions at hub-height from varying methods of estimation.

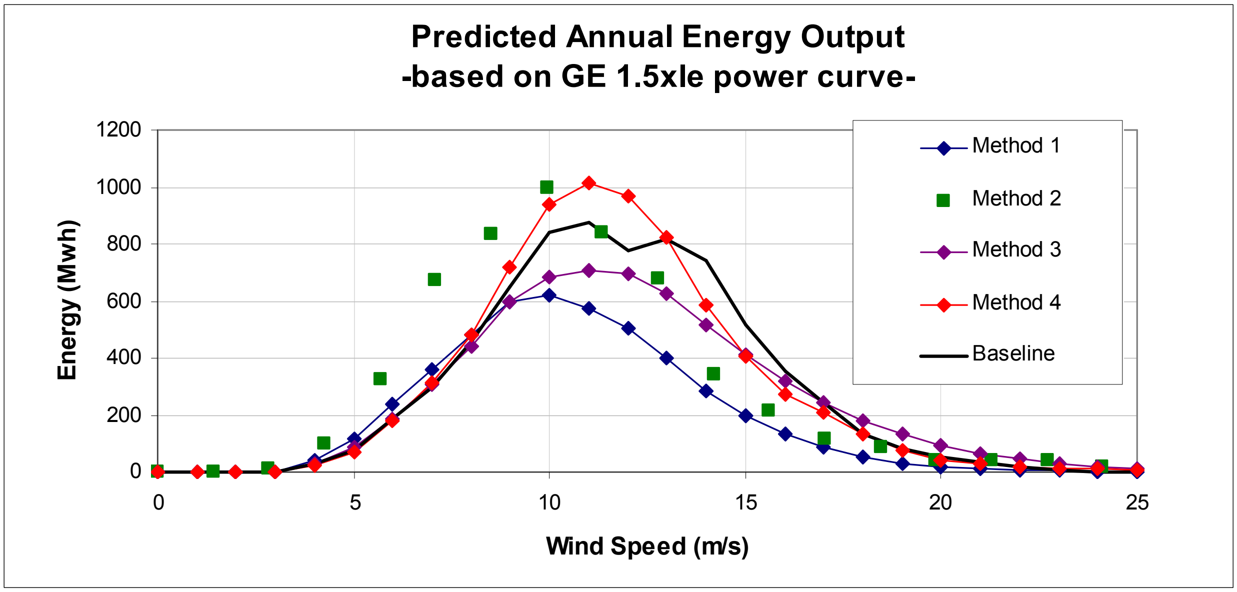

Figure 3. Annual energy output at each wind speed for varying methods of estimation.

Additional Analysis – Preliminary Results

Additional analysis on wind power resource assessment and turbine inflow condition is currently ongoing at the Texas Tech University Wind Science and Engineering Research Center. While these results may be considered preliminary, they provide some robust contributions to the preceding analysis and raise some very interesting questions about the nature of boundary layer wind profiles.

For instance, we introduce another method of potential resource analysis based on Method 2 as explained above. Since it is only a small variation on Method 2, we will call it Method 2.5. In this method, rather than using the 1/7 power law exponent to extrapolate the 10m wind speed bins to hub height, we use the period-averaged 10-78m shear exponent 0.226. As in Method 2, this yields a new set of wind speeds at which the 10m probabilities occur. These probabilities are then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each *new* bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is 7280 MWh, which is remarkably close to the baseline (or "correct answer") of 7191 MWh, an error of only 1.2%. Without an additional data set on which to apply this method, it is unclear whether this result is concrete or merely by chance.

On the other extreme of complexity, we introduce another method that is a slight modification of Method 4. Thus, it is called Method 4.5. Recall that Method 4, assumes that the user has the time-history data from both 10m and some higher height for a site of interest. For each 10-minute interval, a 10-78m shear exponent is calculated, and *that* shear exponent is used to extrapolate the 78m wind speed data point to 116m. Method 4.5 will do exactly the same, except using the time-period-averaged shear exponent of 0.226 in each 10-minute calculation, rather than the shear exponent that is specific to that 10-minute period. From these extrapolations comes a new estimated hub-height wind speed data set. The wind speed probabilities of this data set are then multiplied by the number of hours in a year (8760), and then by the density-adjusted GE 1.5xle wind turbine power curve for each bin to arrive at a bin-by-bin power contribution. The summation of these power contributions is 7211 MWh, a 0.3% error and very close to the estimate that Method 4 itself provides with more rigorous time-specific shear data.

The two supplementary resource analysis methods described above would *seemingly* lend credence to the notion that 10m data, if extrapolated properly, can yield a very accurate estimation of annual energy capture, and that one might be able to use period-averaged, rather than time-specific, shear exponents to approximate energy production. While this **may** be true from an average annual energy capture standpoint, we are finding that less-rigorous or lower-height data do not provide accurate representations of critical aspects of hub-height wind characteristics. For example, the value of wind-generated power will greatly depend on the timing of its delivery. Power generated during the daytime during peak electrical load will generally bring higher returns than off-peak power production at night. As Figure 4 shows, high-level data and time-specific shear exponents are highly dependent on the time of day, and thus crucial in providing an accurate representation of power delivery times.

As we can clearly see in Figure 4, the diurnal nature of wind speed completely reverses between the 10m and 116m levels, with even the 80m data not completely capturing the magnitude of the diurnal variation at slightly higher heights. As a result, peak wind power production timing estimates based on 10m data alone would be completely out of phase with hub-height actuality. Since 10m data would most likely never be used in such a calculation, this result is not entirely critical. What may be of more significant concern to the wind power

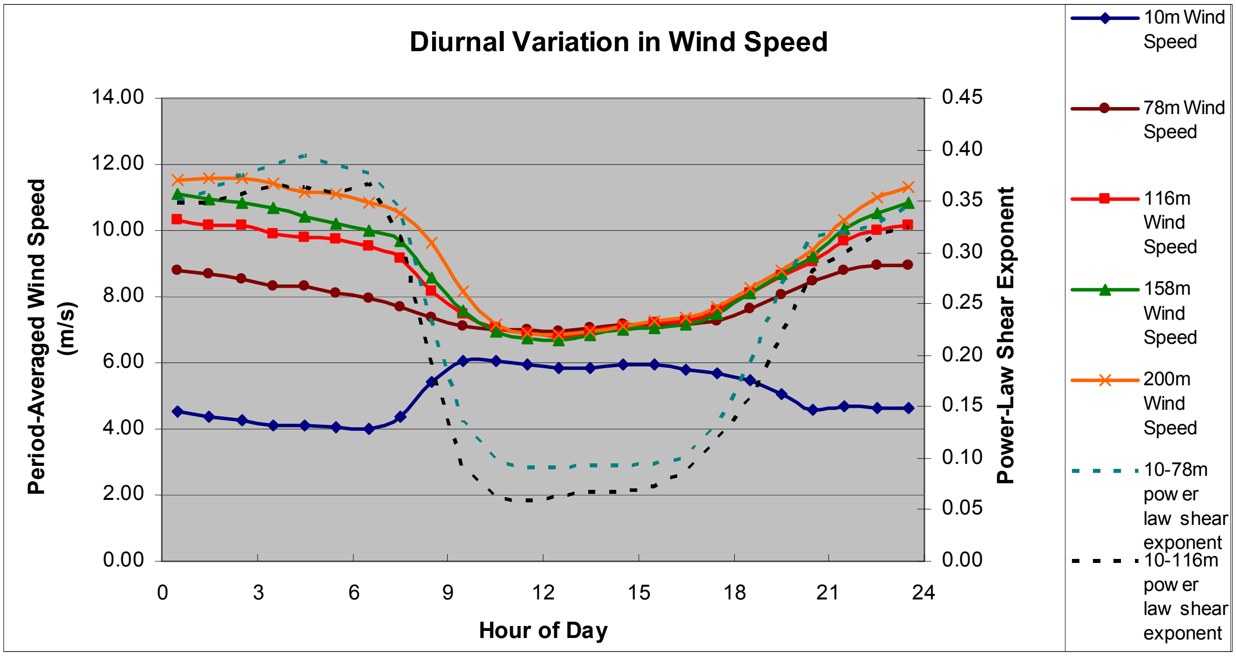

Figure 4. Diurnal variation in wind speeds and power law exponent at multiple heights. Data from February 15, 2005 – December 31, 2005. Reese field site, Lubbock, Texas.

industry is that even wind speed data taken at 50-60m height, the upper extent of most commercial wind resource towers, would fall somewhere within the zone of transition from a daytime to a nighttime maximum and not accurately represent the diurnal variation of the wind speed at higher hub heights. These preliminary conclusions are substantiated by data collected during the tall towers monitoring project in Indiana shown in Figure 5.

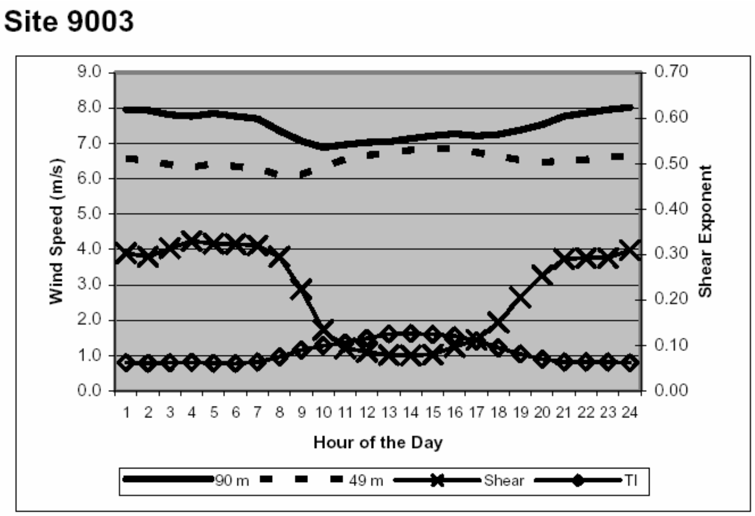

Figure 5. Diurnal variation in wind speeds and shear exponent at multiple heights in northwest Indiana. From GEC "Indiana Energy Group Tall Towers Wind Study – Final Project Report", October 2005, their figure 15.

Figure 5 clearly shows a bimodal distribution in the diurnal variation in 49m level wind speed, with one maximum during the day that can be tied to characteristics of lower-height wind speeds, and another broad maximum at night, which can be tied to characteristics of higher-height wind speeds. It should be noted that extrapolation of 50m data with an average shear exponent will maintain the diurnal shape of the 50m curve, thus under predicting the actual power output at night and over predicting during the day. Using time-specific shear exponents for extrapolation will more accurately bring out the higher-level diurnal character, but will still likely result in some over prediction of power during the daytime hours. If expected production of a wind installation is monitored through revenue generated by power sales, an apparent under performance of the project would be the result. The discovery of this phenomenon in both west Texas *and* Indiana suggest that the meteorological mechanisms that drive it are not necessarily confined to the Great Plains, and that this diurnal wind speed signature likely has significant geographical extent.

The previous figures have clearly depicted the diurnal nature of wind speeds at multiple levels, and thus the diurnal variation of shear exponents. If one examines shear exponent as a function of upper-level wind speed, this bimodal distribution in shear exponent also becomes evident. Figures 6 and 7 show the absolute number of one-hour averages (Figure 6) and shear exponent probabilities ***within each wind speed bin*** (Figure 7), respectively in the 10-116m layer.

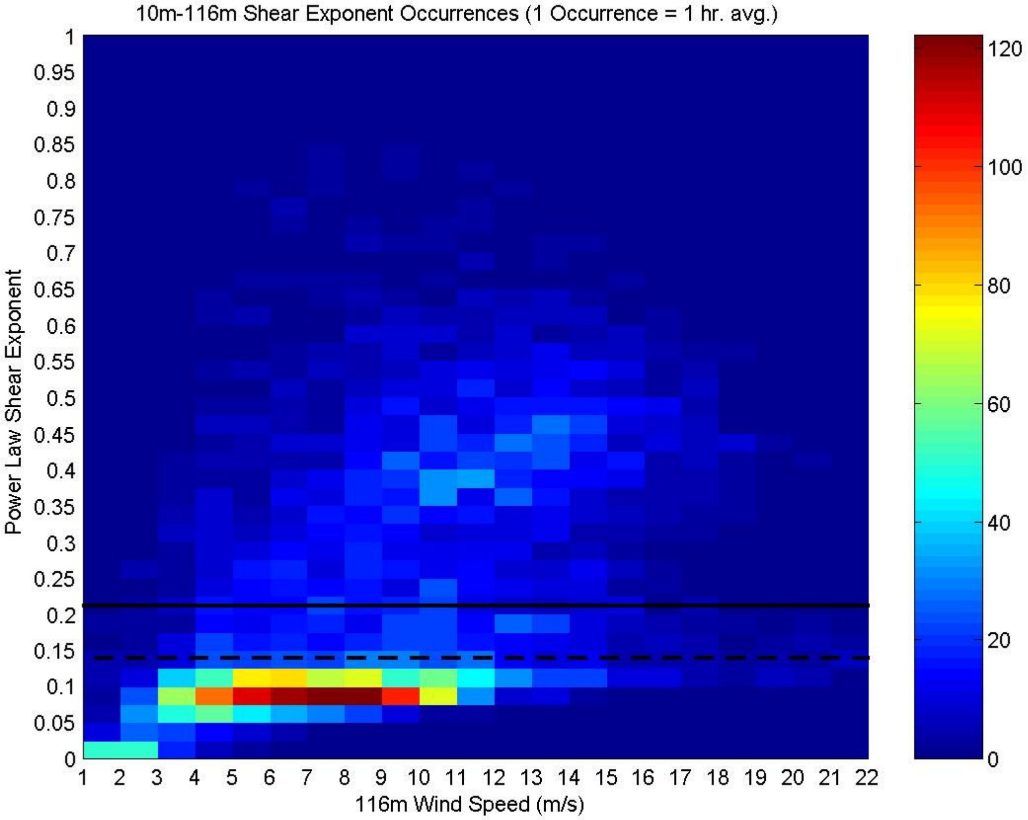

Figure 6. Measured number of occurrences (each is a 1-hr. average) of power law shear exponents in the 10-116m layer as a function of 116m (approximate hypothetical hub height) wind speed. Dotted black line represents 1/7 power law exponent, solid black line represents period-average shear exponent. Data from 200m tower, Reese field test site, Lubbock, Texas.

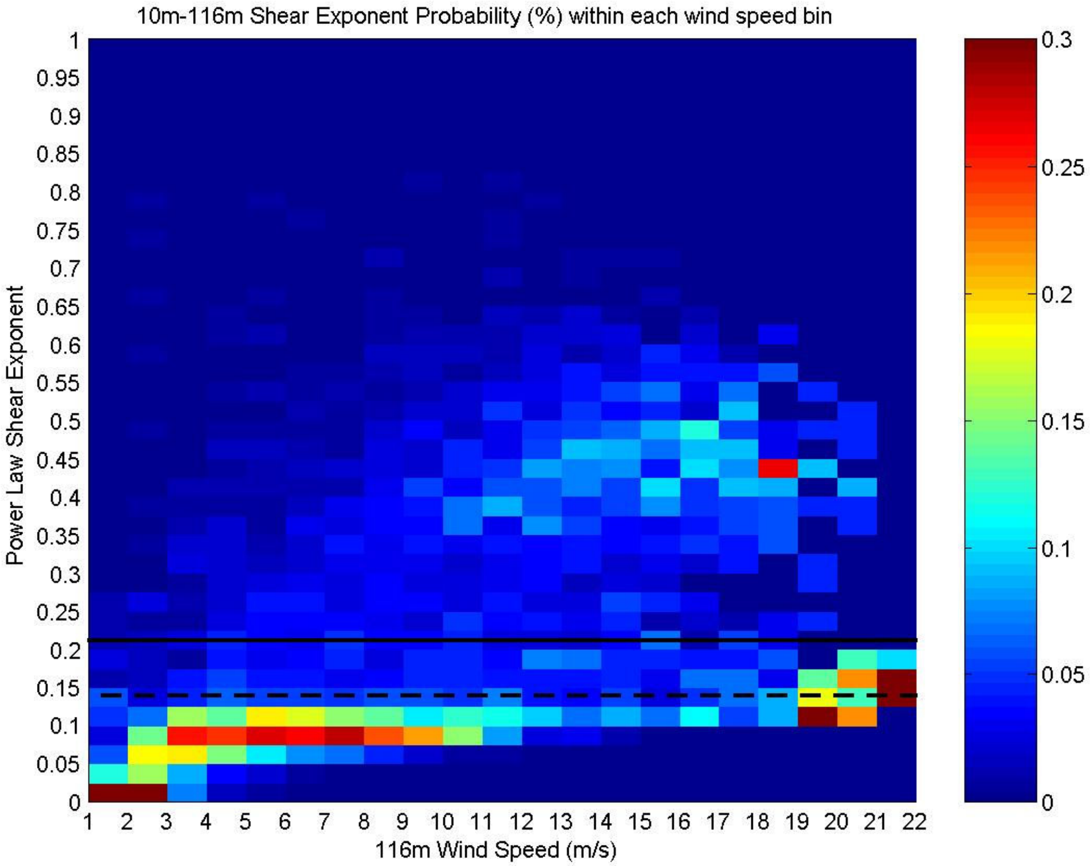

Figure 7. Probability of power law shear exponents in the 10-116m layer relative to other shear exponents *at that wind speed* as a function of 116m (approximate hypothetical hub height) wind speed. Dotted black line represents 1/7 power law exponent, solid black line represents period-average shear exponent. Data from 200m tower, Reese field test site, Lubbock, Texas.

At 116m wind speeds between 0 and 10 m/s and at 20+ m/s, shear exponents have a high probability of being 1/7 or lower. However, a non-trivial spreading to higher shear exponents is seen culminating in a band of increased probabilities in the 0.35 - 0.55 exponent range at 116m wind speeds of 10-20 m/s. While the cause of this signature is not yet known, the secondary peak is hypothesized to be associated with stability in the nocturnal boundary layer and low-level jet processes. The fact that the second peak only appears at *non*-trivial wind speeds lends credence to this hypothesis, and for that reason is believed to be tied to the higher 116m wind speeds and shear exponents during the nocturnal hours shown in Figures 4 and 5. To more accurately isolate the cause, though, future work in this venue will entail plotting shear exponent values as a function of atmospheric stability to more clearly differentiate between stable and unstable conditions characteristic of night and day respectively in the turbine-layer of the lower atmosphere.

Implications

Since the majority of this analysis is an ongoing experiment, “implications” is more appropriate than “conclusions”. With that said, we have found significant evidence that errors associated with the most rudimentary wind resource estimations (Method 1 here) can be very large. In fact, not until there is knowledge of wind speed time histories at both 10 and 78m (Method 4 here) does the error in energy capture estimation drop below 10%. Also, the power law shear exponent used to extrapolate measurements to hub height is of critical importance. Measurements from the TTU 78m tower show a time-period average of 0.226 for the 10-78m power law exponent, well above the commonly-cited 1/7 (0.143). Finally, tall-tower measurements are increasing the industry’s knowledge of the character of wind speeds above the level of common observation platforms (10-60m), with preliminary conclusions showing that lower-level data does not at all capture the diurnal variation of higher-level wind speeds, which may result in an under-performance based on revenue streams from time-variant power sales.

Future Work

Some questions remain unanswered with the preceding analysis. For example, if Method 4 had used data from a 50m tower rather than an 80m tower, how would the results have varied? How does the *uncertainty* of estimation change between methods? How would considering hub-heights higher than 116m affect these results? Plans for future analysis include the investigation of wind speed shear as a function of atmospheric stability to more clearly determine the atmospheric processes responsible for and timing of extreme values in wind speed shear. Some analysis of how these parameters vary seasonally would also be of particular benefit to the wind power industry. Finally, plans to incorporate the phenomenon of wind directional shear with height are currently ongoing.