Research Towards Improved Models for Annual Production of Energy of Small Wind Turbines.
Part I
Why to power curves differ when measured in different locations?
AN OPINION PAPER

by

Mel Tyree, Moderator of SWIEP
Department of Renewable Resources, University of Alberta, Edmonton, Canada

Introduction

The MTC (Massachusetts Technology Collaborative) in late June 2008 suspended a program that provided financial incentives for residential customers to install small wind turbines. By June 2008 MA residents had installed 33 small wind turbines with MTC financial aid, which provided approximately 50% of the cost to install the turbines. The MTC contracted the Cadmus Group to review the installed units and eliminate those with obvious electrical or mechanical problems and summarize the annual energy production of the 19 turbines operating normally (see SWIEP R#17) at http://www.ualberta.ca/~mtyree/SWIEP/Publications.html .
All turbine incentive grants required a pre-assessment of estimated Annual Production of Energy (APE) using industry standard models (such as those in SWIEP R#21). The Cadmus group computed the ratio of Y_m/Y_p = measured APE / predicted APE and the mean was 0.24 with a range from about 0.1 to 0.6 (see more details in SWIEP R#35 for more details). The MTC wishes to promote renewable energy systems in the State of MA and continues to provide incentives for small scale solar- and water-generation of electric power. But the MTC wants to give grants only to productive systems. Given the failure of industrial standard models to predict APE in MA, the MTC suspended the incentive program until a more reliable model can be formulated.

I have, coincidentally, been interested in models of mass and energy transfer for 40 years and recently grew interested in wind turbine models for APE when I noticed that my 10 kW Bergery turbine in Ellenburg, NY, had a Y_m/Y_p value of 0.6. Subsequently I have performed a sensitivity analysis of the model (SWIEP R#22). A sensitivity analysis does NOT validate a model, but provides background information of the sensitivity of Y_p to input variables and parameters. Such information is useful for model building and in designing protocol for validation. The model for Y_p requires an accurate power curve, P_c, i.e., a plot of kW power output for a turbine versus wind speed, v. In the process of doing sensitivity analysis I realized (1) accurate power curves are essential and (2) P_c curves when measured on the same make and model of turbine can change when performed at different sites.

Why do power curves differ when measured at different sites? What is the impact of differing P_c curves on estimation of Y_p? If we understand why power curves differ at different sites can we incorporate this improved understanding in building a more predictive model of APE? The purpose of this opinion paper is to address some of these issues.

Two power curves measured on a 10 kW Bergey turbine.

Below are the power curves of two 10 kW Bergey turbines measured at two different sites. Two curves were generated in Colorado (a flat area with little vegetation) and one was generated at Alfred University, NY, (at a rural farming area with gently rolling hills, pastures, farm buildings and tree-lined wind breaks).

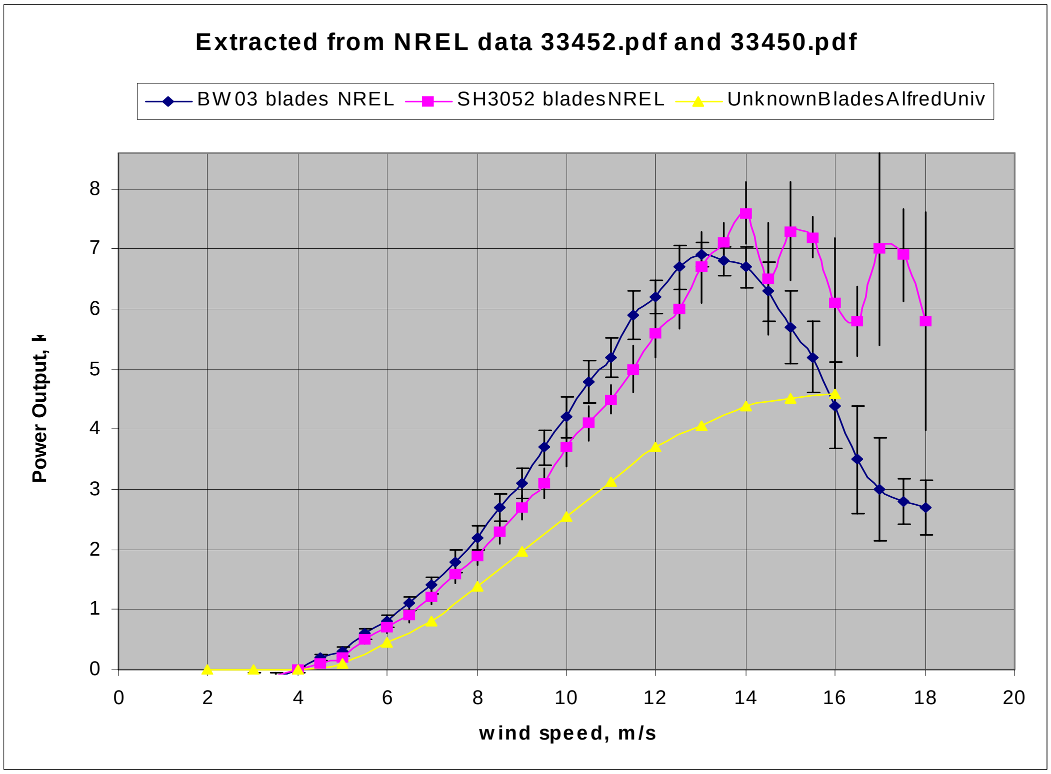


Fig. 1: NREL = US Department of Energy, National Renewable Energy Lab.
These curves show output power (kW) versus wind speed. Note that the curve obtained at Alfred University seems much lower. The error bars are NOT standard deviations (SD), rather they are 'combined uncertainties' based on an error analysis of the accuracy of sensors used in the study.

How important are these differences when used in Y_p prediction? I put the NREL curve (SH3052 blades) and the AU (Alfred University) curve into predictive models for APE for my site in Ellenburg, NY, and found the AU curve predicted that APE was only 0.39 of the value predicted by the NREL power curve for a mean annual wind speed ($\bar{v}$) of 5.5 m/s. The standard procedure for the prediction of Y_p is to used the NREL curve at other sites after making corrections for differences in site condition (elevation, site turbulence, site location, e.g., continental versus island versus ocean sites etc). The model also needs a way of predicting the annual variation in wind speed based on $\bar{v}$ and some site descriptors. In my comparison, the only thing I changed was the power curve P_c, hence we really need to understand why power curves differ between sites if we are to improve models.

Why the power curves might differ:

There are a number of reasons that can be advanced to explain the differences in Fig. 1. Here is a possible list from the most ‘banal’ to the most ‘profound’.

1. The people at Alfred University who did the power curve are idiots and can’t be trusted to do good work.
2. Since wind velocity was not measured precisely at hub-height there could be serious errors.
3. There might be something wrong with the GridTek10 inverter at Alfred University that resulted in a low power curve.
4. Turbulence changes the ‘probability density function’ of wind speeds hence might change the power curve assuming the turbine can respond to all wind gusts equally.
5. Turbulence might affect the way a cup anemometer senses wind speed in a way that is significantly difference from how a turbine responds to wind speed. We would expect a low-mass cup anemometer to be more responsive to wind gusts than a high mass turbine (SWIEP R#28).

In response to the above options, I tender the following replies:

1. *Alfred University staff were idiots*. I doubt it! The principle investigator was the head of the Engineering Department. His work was funded by and was done in consultation with NYSERDA (New York Energy Research and Development Authority). They used the same kind of data logger and power transducer sensors as employed by NREL. They also sampled bin values of power and wind speed like NREL did. I believe that Alfred University Engineering faculty would know enough about Electrical Engineering 101 to teach the course and do measurements properly even if they are not professional EEs.

2. *Wind speed measurements were in error.* Wind speed measurements might have been slightly in error but perhaps NOT in the direction or magnitude to help the situation. Wind speed was measured on the turbine tower at two heights (12 m and 24 m) and the turbine hub was at 30 m. They measured wind shear (= 0.2) and used that to estimate v at hub height. If the wind shear equaled 0 (unlikely) the v at hub height would equal the v at 24 m. If the wind shear were double (=0.4) the v at hub height would be even lower than in Fig. 1. See the possible range of errors below (Fig. 2). Conclusion, more wind shear would make the disagreement between the curves MORE and even with no wind shear we cannot make the two curves merge.

3. *The GridTek10 has problems.* I cannot eliminate this one. Bergey Inc has had a history of quality control for inverters. At the time my inverter was delivered (2005) approximately half the inverters shipped to NY were untested and had problems sometimes related to efficiency of power conversion (personal communication with NY State installers). So I cannot eliminate this option. We will set it aside for now.

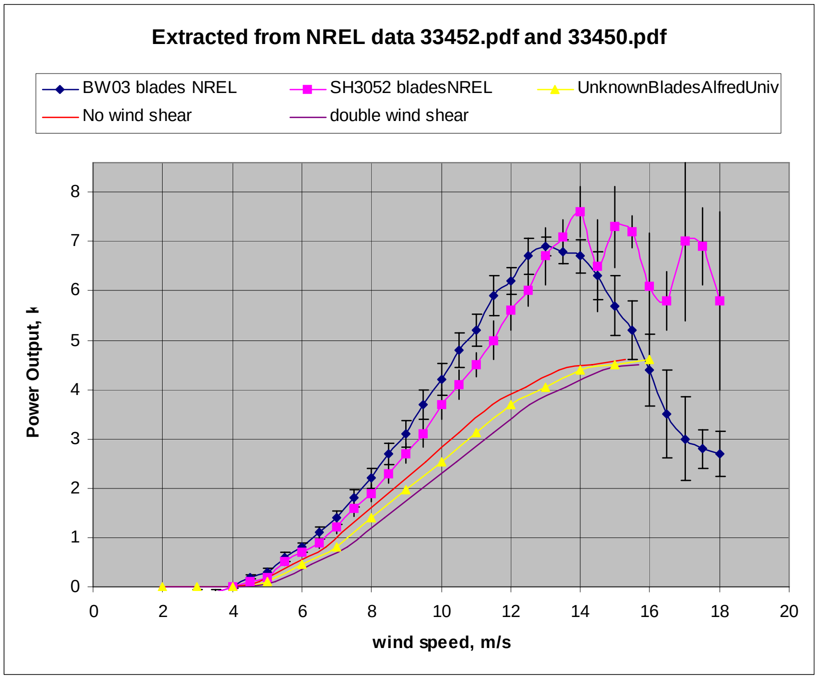


Fig. 2. Shown again are the three power curves (P_c) in Fig. 1. The solid red line is the Alfred University P_c corrected on the assumption that there is no wind shear (impossible). The lower purple line shows the P_c with double the wind shear (much more likely).

4. *Turbulence changes the 'probability density function'*. To understand this I have to explain who P_c curves are measured and 'bin' values collected. When collecting data for P_c curves P_c values and *v* values are collected at 1 Hz (once per second) and averaged by a data logger (usually a Campbell Scientific) and saved once per 10 min together with standard deviations (*SD*). Hence each mean and *SD* is based on 600 measurements. The mean values of *v* are 'binned', i.e., all means of *v* and P_c and the corresponding *SD* are saved in common 'files' with common *v*. These bins are in multiples of 1 m/s or 0.5 m/s. For example if you bin in 1 m/s intervals and you are 'binning' values for 6 m/s, you will save in the same 'file' all means of *v* and corresponding P_c and *SD* that are between $v =$ 5.5 and 6.5 m/s. This 'standard' method of binning causes a huge *SD* and the averages cover a wide range of values that enter into the mean. A probability density function is a way of expressing how wide this range is based on saved values of means and *SD*.

5. *Turbines and cup anemometers do not respond to wind gusts in the same way*. I have never seen a proper quantitative treatment of this issue. I am looking into it and I will report about it later. But I think it can be important. See Conclusions for more detail.

The remainder of this opinion paper deals primarily with option (4).

Probability density functions and turbulence index.

The turbulence index is DENFINED the same as the statistical term: coefficient of variation, C_v = *SD*/mean. Lets look at some turbulence index values as measured by cup anemometers by the MTC.

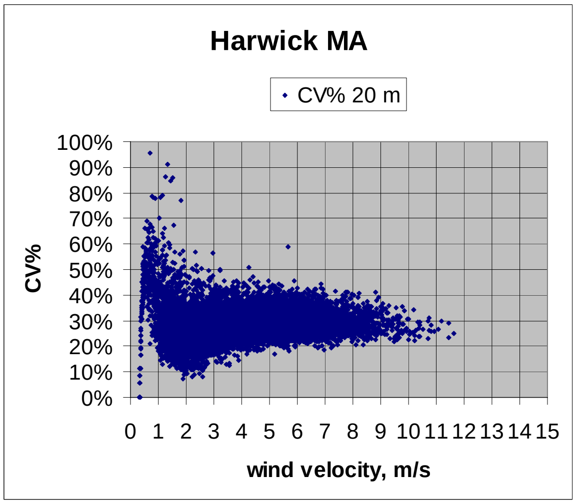


Figure 3. About 2000 turbulence intensity readings measured at 20 m (1 Hz sampling 10 min bins) measured in Hardwick, MA.

The turbulence intensity is due to wind shear (fast moving wind moving over slower moving wind near the ground). This rubbing of wind causes wind eddies (turbulence). Turbulence is also caused when air is warmed by the sun near the ground. The warm air rises and collides with faster moving air higher up. Turbulence intensity increases also when fast moving air collides with surface roughness (buildings, trees, shrubs, hills etc). Turbulence intensity is most near the ground, which can be seen clearly when we plot mean turbulence intensity versus velocity and height above the ground (Fig. 4)

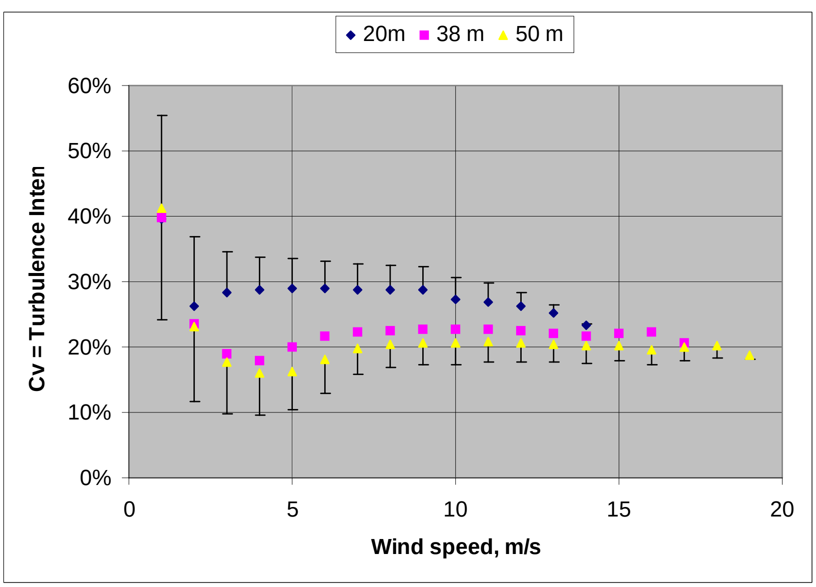


Figure 4. Mean C_v = turbulence intensity plotted versus wind speed and at three heights. Bars on some points give examples of *SD* on *C*v values.

What does C_v mean when plotted in terms of variation of wind speed? This is what a probability density function allows you to see. If you measure mean wind speed (say at 1 Hz over 600 s) and also compute *SD*, you can plot a probability density function which gives you a picture of how much the wind speed changed during those 600 s. Here are the density functions for a C_v = 0.15 in Fig. 5.

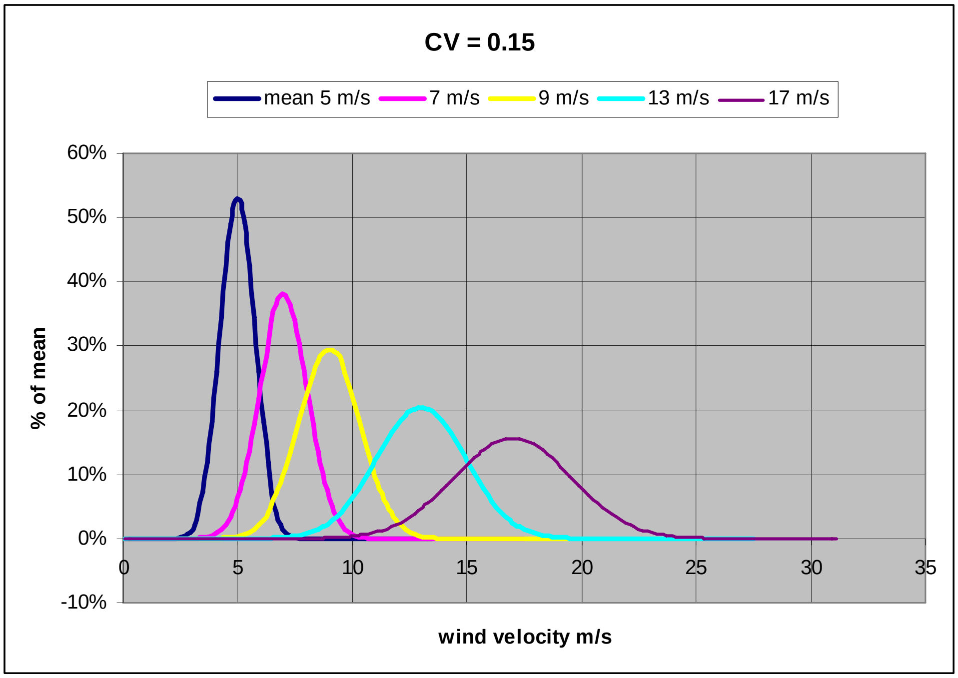


Figure 5. Probability distribution functions (= variation in wind speed) for several binned wind speeds. The peak of these Gaussian distributions = the mean, the spread represents the spread in wind speed. The means are centered on the bin values of 1 m/s interval. Hence a mean of 16.5 m/s is the binned probability density function of all means in the range of 16 to 17 m/s. Notice the huge overlap covering 6 to 8 bin means to the left! Only every 4th bin mean is shown for clarity. The C_v values used is close to the NREL value.

From Fig 5, you can see that bin means used in power curves cover a huge range in velocities and hence a huge range in power production. How much is the likely range in power production entering into each point in Figure 1 or 2? I have measured P_c at 1 Hz on my Bergey turbine in Ellenburg, NY. The time sequence of *P* for *P* values binned by average *P* bins of 1 kW are shown in Figure 6a and 6b. As you can see, *P* varies all over the 'map' at any one 10 min bin value.

BOTTOM LINE: The typical power curve contains very noisy data (from a statistical standpoint). Also turbulence intensity varies a lot between sites, for example it is somewhere between 0.1 and 0.15 at the NREL test facility, 0.28 at the Alfred University test site and can be up to 0.4 at some turbulent sites near high surface roughness where some small wind turbines might be located. Could differences in turbulence intensity explain differences in power curves?

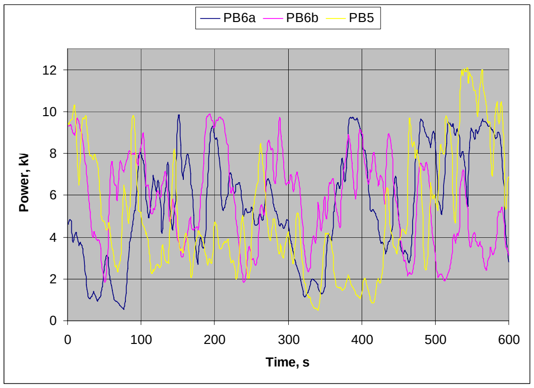


Figure 6a: Power (kW) vs time, s. PB6a = 10 minute bin with mean = 5.6 C_v = 0.47, PB6b mean = 5.7 C_v = 0.38 PB5 mean = 5.0 C_v = 0.58

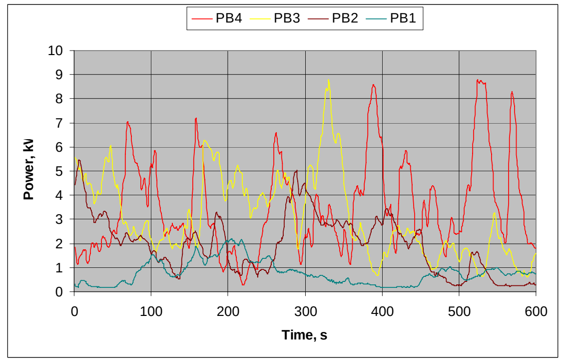
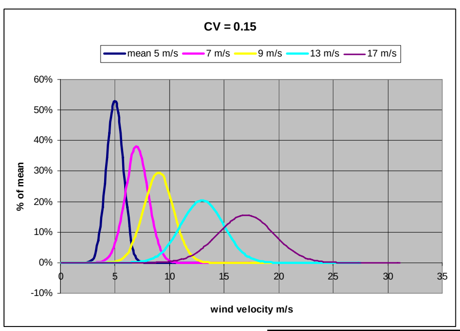
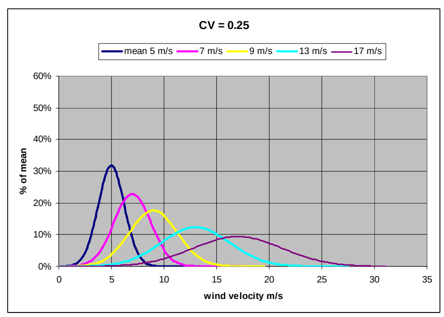


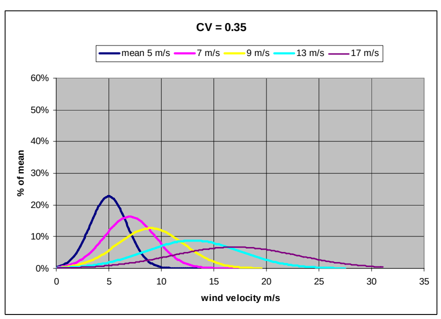
Figure 6b: Power (kW) versus time, s. PB4 = 10 min bin with mean = 3.5 C_v = 0.55. PB3 is mean = 3.1 C_v = 0.55, PB2 mean 2.0 C_v = 0.62 PB1 mean = 0.8 C_v = 0.6

Theoretical effect of Cv on power curves.

Lets start out by looking at the impact of C_v on probability density functions.







From the three graphs above, it can be seen that the potential impact is huge. At C_v =0.35 the 17 m/s binned mean value of v (wind speed) covers the entire range of v in the power curve in Figure 1! Now this spreading of wind energy may not be all bad in terms of total annual energy yield (Y_m or Y_p). The energy contained in wind is given by: $P = 0.5\rho A v^3$, where ρ is the air density and A is the turbine sweep area. Hence P increases with the cube of v. Look at the curve for mean 17 m/s C_v =0.35. Half of the mean v is distributed to low energy wind but half is distributed to high energy wind. Because of the 3rd power relationship of P = power in wind, you gain more in wind energy on the right side of the density function than you loose on the left side. So power curves in a more turbulent site should be better than in less turbulent sites. Right? NO Wrong! Look at Fig. 1. The Alfred University site had a C_v = 0.28 but the NREL site was around C_v = 0.12 but the power curve is lower. So why is that? The amount of wind energy captured by a wind turbine is given by $P = 0.5\rho A v^3 C_p$, which C_p measures the fraction of wind energy the turbine can capture. This value is < 1 and is NOT constant over the range of v in a power curve. If C_p where **constant** then a turbulent site MIGHT potentially yield a higher power curve than a less turbulent site PROVDIDE all wind gusts can be captured regardless of the speed of the gust. LOOK at Fig. 6. Winds are very gusty as judged by how fast P_c goes up and down.

So if we take into account how C_p changes with v do we gain or loose in power curves ASSUMING a turbine can get energy from gusty wind no matter how fast the gusts come on and die away? I have completed the modeling to answer this question.

<u>A Model to Address Question (4) on Page 3.</u>

The approach to investigate the impact of C_v on power curves is to us the values of C_v and mean speed, $\bar{v}$ to compute the Gaussian probability density function $\Gamma(v)$ for the distribution of wind speeds around the mean. $\Gamma(v)$ is usually given in a statistical form which I will modify for wind symbols:

$$\Gamma(x) = \frac{1}{\sigma\sqrt{2\pi}}\exp\left(-\frac{(x-\mu)^2}{2\sigma^2}\right) = \frac{1}{C_v\bar{v}\sqrt{2\pi}}\exp\left(-\frac{(v-\bar{v})^2}{2(C_v\bar{v})^2}\right) \qquad (1)$$

In statistics μ and σ are the symbols used for mean and *SD*, respectively, but wind symbols we are using $C_v = \sigma/\mu$, $\bar{v} = \mu$ and $v = x$, and when you make these substitutions you go from the equation in the middle to the equation on the right. When I started working with Gaussian density functions I didn't believe that wind speeds could vary as much as predicted by Eq. (1). However, I consulted a wind expert, John D. Wilson, in the Department of Earth and Atmospheric Sciences, University of Alberta, and John told me that Gaussians are quite good at the higher wind speeds >4.5 m/s, which is in the range of speeds of use to wind turbines. I expressed disbelief, but he said he was sure and offered to give me data sets measuring v at 20 Hz (with a sonic anemometer) to prove it. I have got these raw data and will take a look soon, but will take John's word for what follows.

An internal test of the model is to use the C_v values at the NREL site and use these C_p values to see if you can reconstruct the measured power curve P_c at the NREL assuming (1) Gaussian density functions apply and (2) assuming that the turbine can respond instantly to rapid fluctuations in v (= turbulent eddies) no matter how fast the eddies pass through. To this end I broke Eq.(1) into discrete v bins of 0.2 m/s increments starting with a low centered value of 0.1 and increasing in steps of 0.2 to 33 m/s. The NREL C_p values are given only in bins of 0.5 m/s increment. So these values were interpolated AND smoothed to give C_p in 0.2 m/s bin increments. Smoothing was required because C_p was given only to two significant figures, e.g., for the 10 kW Bergey the peak values were 0.21 or 0.20 which resulted in step-like changes of C_p with v. These step changes in v

were smoothed out to give values of C_p to 3 or 4 significant figures. At each $\bar{v}$ (mean speed) in the NREL power curve the Gaussian-derived power ($P_{Gaussian}$) was computed from:

$$P_{Gaussian} = \sum_{i=1}^{N} \Gamma(v_i)(0.5\rho A v_i^3 C_{p,i}) \qquad (2)$$

In Eq.(2) ρ = air density, N = number of bins, and A = sweep area of the turbine blades. This computation method is very similar to what is done to estimate Y_p (annual production of energy) in the industry standard model. Except in this case mean $\bar{v}$ are used with a Weibull probability density function of annual v distribution. Eq. (2) basically uses 10 min bin values of v to compute $P_{Gaussian}$ for a 10 min period versus the standard method that uses annual binned values of $\bar{v}$ and a Weibull function to estimate Y_p over a 1 year period. It is the same idea, but the time scale is different. See SWIEP R#22 for more details on Y_p estimation with the current industry standard model.

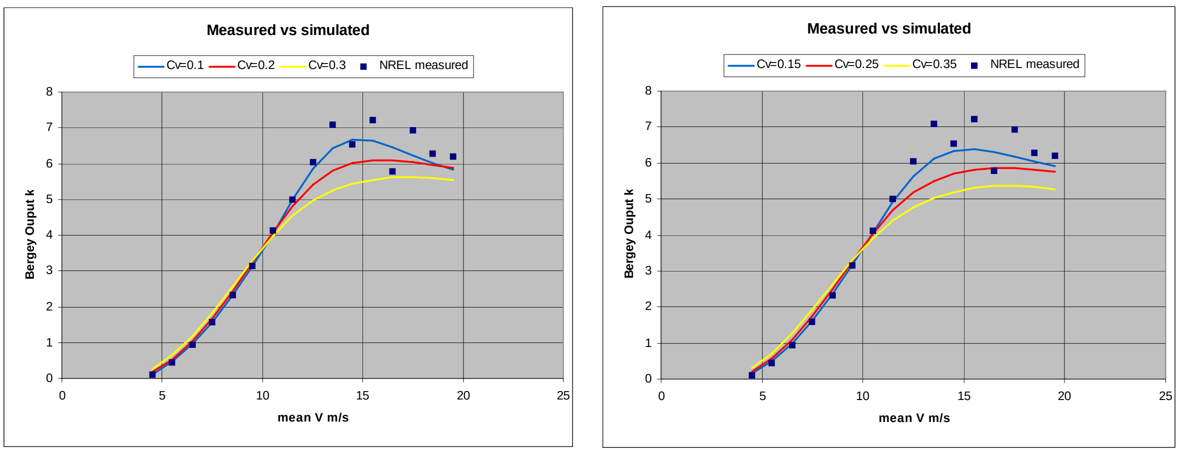


Figure 7. Above are measured and simulated values of a power curve P_c = kW output versus mean wind speed. Smooth lines are for simulated values of $P_{Gaussian}$ and the squares are the actual measured values of P_c.

The biggest uncertainty with this model is that C_p is undefined (unmeasured) at $v > 20$ m/s, but values of C_p are required at the higher v values. The conservative approach is to assume that P_c remains constant above v = 20 m/s. This was done in Fig. 7 by making $C_p = P^* / 0.5\rho A v^3$, where P^* = a constant power output. If , on the other hand, P^* continues to fall as v increases then C_p falls faster, which is the more likely case because auto-furling of the Bergey will cause power to continue to fall as v exceeds 20 m/s. In the extreme case where power falls to zero then C_p=0. I have computed this extreme case. The curves are very similar, i.e. the agreement between $P_{Gaussian}$ is still close to P_c up to v = 11 m/s (near the maximum output), but the $P_{Gaussian}$ curves fall off faster for v>20 m/s. I have done similar model calculations for the SkyStream turbine, with qualitatively similar results. If you want to see my entire model on an Excel sheet download SWIEP R#31.

Conclusions

I have modeled for the impact of Gaussian distributions on power curves assuming that a turbine responds to all wind gusts no matter how fast they pass by. When you model for Gaussian distributions approximating the NREL site (C_v between 0.1 and 0.15) you get a good match between predicted and measured power curve, P_c. When you run the simulations for sites with higher turbulence index (higher C_v) you do NOT get such a good match. The computed $P_{Gaussian}$ distributions fall below the measured values for $v >$ 10 or 12 m/s (Fig. 7) but are slightly higher for $v <$ 10 m/s. This is contrary to the observations at the Alfred University test site (Fig. 1), where ALL P_c values are less than the NREL values.
Hence we are left with reasons (3) and (5) on page 3 to explain the difference in power curves measured at different sites.

Mike Bergey has informed me that quality control problems with GridTek10 inverters happened ONLY during the years when Xantrex moved production of the GridTek10 to Mexico. Xantrex production of the GridTek10 is now back in NJ like it was when the Alfred University site was built. I tentatively accept Mike's word on this even though he has a history of exaggerating the truth when talking to customers, e.g. SWIEP R#23 and numerous conversations I have had with installers regarding multiple issues. It is obvious that GridTek10 inverters are shipped to customers without any quality control testing hence the customers become the 'test sites' for quality control.

This leaves reason (5) on page 3 is our remaining option. Turbulence of wind can be described by a spectrum of component frequencies according to my wind guru, John Wilson. I have taken a brief look at raw wind data collected by John with a sonic anemometer. A sonic anemometer uses the Doppler-effect to measure gustiness of wind speeds with a precision of 4 significant figures and an accuracy of better than 0.3 %. The data I examined took wind speed measurements at 20 Hz and it was obvious that wind eddies move through very rapidly. A cursory examination of turbine output data like those in Fig. 6 suggests that a Bergey has a response time of a few seconds.

In my next opinion paper I will compare the power frequency spectrum of my Bergey in Ellenburg, NY, to get an idea of how fast (= at what frequency) Bergeys can respond to wind gusts. I will compare this to power spectrum of wind, i.e., the frequency spectrum of v^3 versus frequency of turbulent air.

Stay tuned to this channel,

Mel Tyree, Moderator of SWIEP
Department of Renewable Resources, University of Alberta, Edmonton, CA.