N83 19254

POTENTIAL ERRORS IN USING ONE ANEMOMETER TO CHARACTERIZE THE WIND POWER OVER AN ENTIRE ROTOR DISK

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INTRODUCTION

There has not been much consensus in the wind energy industry on wind measurement strategies used to site large wind turbines. Since energy production estimates based on the wind measurements directly affect the expected cost of energy (and therefore the viability of a site), it is critical that appropriate wind measurements be taken.

A key issue of concern has been what height(s) above ground the wind should be measured. Essentially, there are three strategies:

1. measure continuously at one height on a short tower, typically 10 m. This is relatively inexpensive, but requires one to assume a vertical profile to estimate winds in the approximately 15 to 100 m layer in which a large turbine operates.

2. measure continuously at 10 m and intermittently at higher levels (e.g., kites) to estimate the wind shear with height.

3. measure continuously at three or more levels on a tall (roughly 60-150 m) tower, suitably representative of the entire rotor disk. This is by far the most expensive, but one can determine actual effective rotor disk winds.

Wind data collected at four levels on a 90-m tower in a prospective wind farm area are used to evaluate how well the 10-m wind speed data with and without intermittent vertical profile measurements (strategies 2 and 1, respectively) compare with the 90-m tower data. If a standard, or even predictable, wind speed profile existed, there would be no need for a large, expensive tower. This cost differential becomes even more significant if several towers are needed to study a prospective wind farm.

When only 10-m data are available, wind speeds are typically extrapolated with a vertical profile power law to determine the corresponding hub height wind:

$$V_z = V_{10} \left(\frac{z}{10}\right)^{\alpha}$$

where

V_z = wind speed at hub height

V_{10} = wind speed at 10 m

z = hub height (m)

α = power law exponent

This extrapolated speed is then used to estimate power output of a turbine. One major problem with this approach is how to specify the power law exponent α. A value of 1/7 is often used because literature cites it as a typical or average value.

However, this is a great oversimplification and may be totally inappropriate. The vertical profile of wind speed is a complex function of surface roughness (Munn, 1973), stability/time of day (Mahrt and Heald, 1979), and topographic orientation (Hiester and Pennell, 1981).

Over flat terrain the 1/7 power law may be reasonable. But most sites for wind energy development will be on hills, ridges, or in passes; i.e., terrain features likely to accelerate or retard flow in the surface boundary layer. Data from Pacific Gas and Electric Company's (PGandE) 90-m tower demonstrate that alpha over such terrain can be substantially less than 1/7.

STUDY PROCEDURES

Three items are discussed in this section:

- PGandE wind energy measurement program.
- The data base used for evaluating monitoring strategies.
- Processing of the data.

PGandE Wind Energy Measurement Program

PGandE has been investigating wind energy potential in the Solano County area near San Francisco, California for the past few years. This area is a low gap in the central California coastal range through which cool marine air streams eastward into the interior valley during the warm season (Figure 1).

There are currently eight monitoring sites in Solano County--five 10-m towers, two 30-m towers, and one 90-m tower. The 90-m tower, called S-01, is located on a flat spur ridge east (downwind in summer) of the main ridgeline of the area (Figure 2).

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The 90-m tower was installed in June, 1980. There are four monitoring levels--10, 30, 60, and 90 m. Wind speed and direction are measured by a Teledyne Geotech Model WS201 Wind Systems. One-half second averaged samples are recorded every two seconds. These data were recorded only on strip charts until mid-September, 1980. After this date, processed data were recorded on cassette tapes in addition to the strip charts.

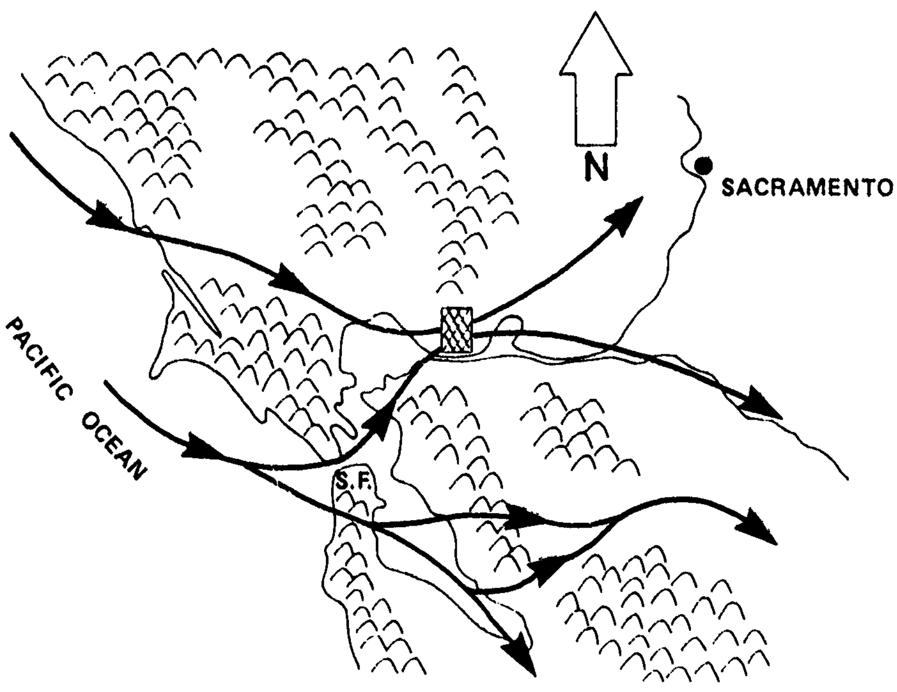

FIGURE 1. TYPICAL SUMMER AIRFLOW PATTERNS IN THE SAN FRANCISCO BAY AREA. SOLANO AREA MARKED WITH CROSS-HATCHING.

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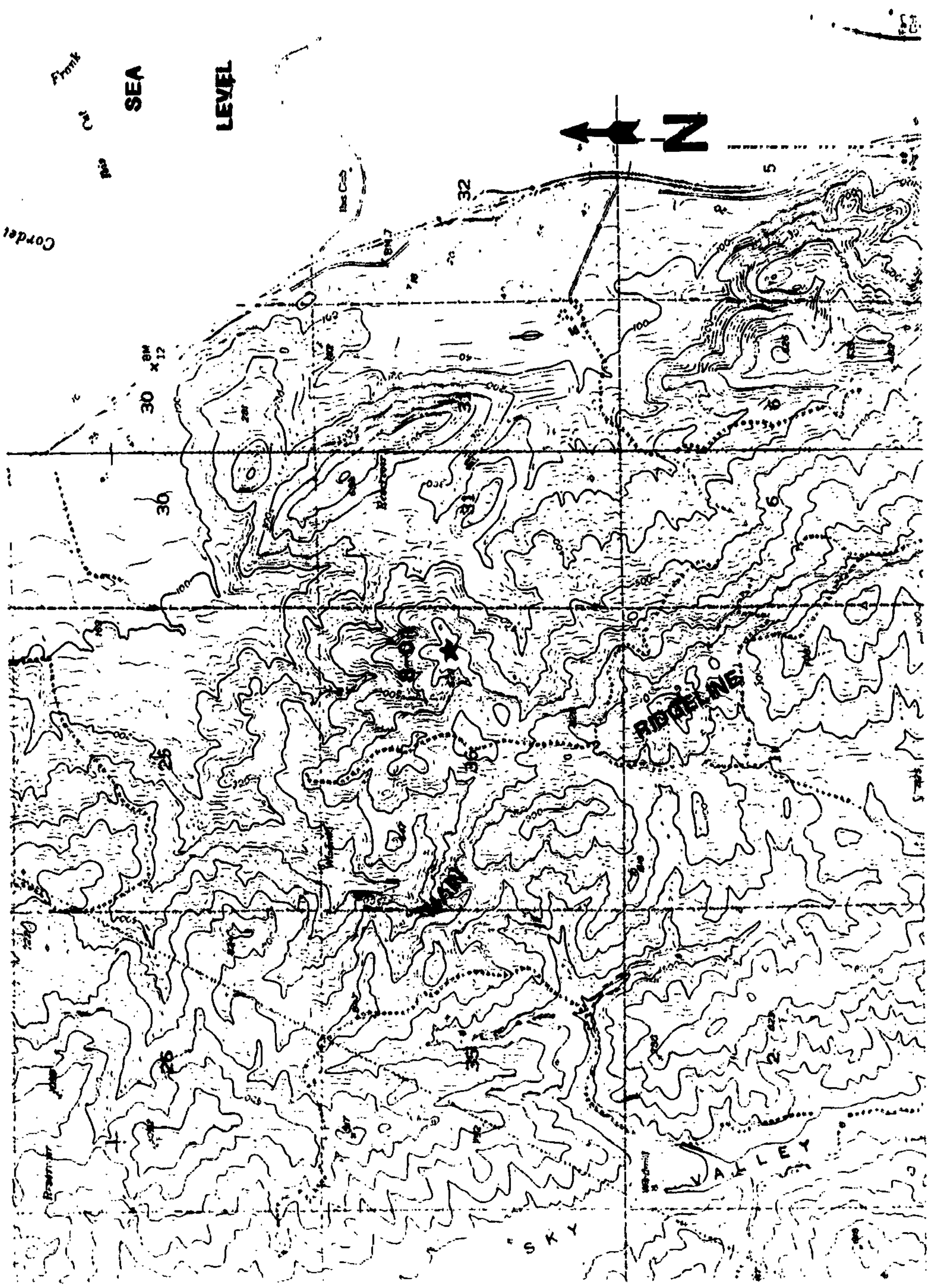

FIGURE 2. S-01 SITE MAP. ELEVATIONS IN FEET.
1 inch = 1 km.

Data Base Used for Evaluation of Monitoring Strategies

Since summer is the peak wind season, it was selected to be the data base for this study. The exact dates are June 14, 1980, to September 30, 1980.

Only hours with valid wind speeds at all four levels of a tower were used. There were 2163 hours meeting this requirement, 83 percent of a possible 2616 hours.

One direct and five indirect techniques for estimating the effective rotor disk wind speed were chosen, and a data set with these six estimates for all valid hours was generated for further analysis. Since PGandE had purchased a BWT 2560 (MOD-2), its performance curve was chosen for use in this study. The six techniques were:

1. Effective rotor disk wind speed. This is the direct technique. It is a cubic-weighted mean incorporating all four wind speeds and wind directions. It assumes that all parts of the rotor disk contribute equally to the energy production, subject only to variations in wind speed across the disk (Jim Connell, PNL, personal communication). The formula for a BWT 2560 is:

$$\mathrm{VRD} = \{[0.11(V'_{300} + 0.25(V'_{300} - V_{200}))^3] + [0.049(V'_{300} + V_{200})^3] + [0.049(V_{200} + V'_{100})^3] + [0.11(V'_{100} + 0.35(V'_{30} - V'_{100}))^3]\}^{1/3}$$

   where VRD = the effective rotor disk wind speed, V' = the wind speed at a given level multiplied by the cosine of the angle between the wind direction at that level and the wind direction at 60-m. (This accounts for direction shears.)

2. Wind speed at 10 m. This technique assumes no change of wind speed with height ($\alpha = 0$).

3. Wind speed at 60 m (hub height of a BWT 2560).

4. Wind speed at 10 m extrapolated to hub height with a 1/7 power law. This is the conventional method used in most site evaluations.

5. Wind speed at 10 m extrapolated to hub height with an alpha derived from 5 random days of 90-m tower data, using only hours between 0500 and 2000 PST when the 10-m wind speed exceeded 4 mps.

This exponent α was computed slightly differently. The usual method is to use the 10-m and 60-m wind speeds to get the power law exponent between those levels. However, we replaced the 60-m wind speed with VRD, since VRD is the direct estimate of the rotor disk wind speed. Based on this method, the effective exponent at S-01 was 0.06.

6. Wind speed at 10 m extrapolated to hub height with an exponent derived from a randomly-selected four-day period of 90-m tower data. This technique is identical to (5) except for the dates. At S-01, the exponent was 0.04.

For sake of brevity, abbreviations for these different techniques will be used as follows:

VRD--effective rotor disk wind speed

V10--10-m wind speed (no extrapolation)

V60--60-m wind speed

HUBXP--10-m wind speed extrapolated with $\alpha = 1/7$

HUBK1--10-m wind speed extrapolated with α determined from five random days of tower data.

HUBK2--10-m wind speed extrapolated with α determined from four consecutive days of tower data.

Processing of the Data

The following were computed for the entire study period:

- Wind rose (VRD only), using 60-m wind direction
- Mean diurnal speeds (all techniques) and mean diurnal α (10-VRD)
- Mean available power (all techniques)
- Frequency distributions of α (10-VRD and 60-90)
- Frequency distributions of wind speed (all techniques)
- BWT 2560 power output simulations (all techniques)

A comparison of summer and winter mean profiles was also made. Results are discussed in the next section.

*The 95 percent confidence limits for estimating the mean summer α computed this way (five random days) were about ±.02 from the actual mean.

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RESULTS

Wind Rose

The wind rose for S-01 is shown in Figure 3. Summer winds are from the southwest through west with only minor exceptions.

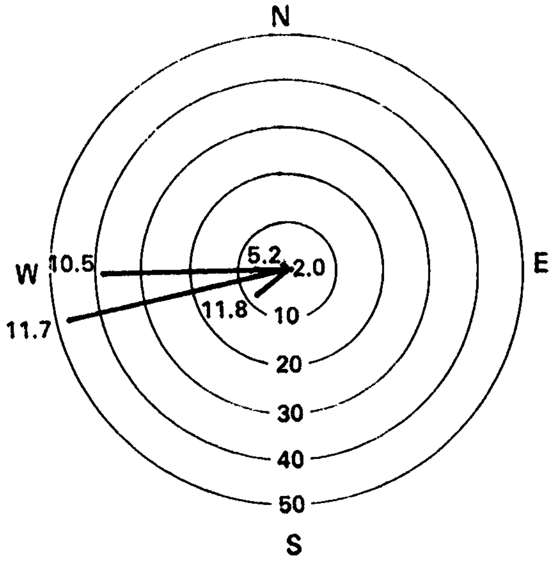

FIGURE 3. S-01 WIND ROSE, SUMMER 1980. AVERAGE WIND SPEED (mps) GIVEN FOR EACH DIRECTION, PERCENTAGE FREQUENCY OF EACH DIRECTION INDICATED BY CIRCLES.

Mean Diurnal Speeds

Mean diurnal and overall wind speeds are shown for S-01 in Table 1.

Clearly this site does not exhibit a standard vertical profile. There is a reverse in the mean wind shear, with highest winds occurring at 60 m.

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TABLE 1. MEAN DIURNAL WIND
SPEEDS (mps) AT S-01, JUNE 14, 1980 - SEPTEMBER 30, 1980

		Speed							
Hour (PST)	Number of Observations	V30	V100	V200	V300	VRD	HUBXP	HUBK1	HUBK2
01	90	11.3	12.4	12.7	11.6	12.2	14.8	12.6	12.2
02	90	11.1	12.3	12.4	11.4	12.0	14.6	12.5	12.0
03	89	10.9	12.0	12.2	11.3	11.8	14.3	12.2	11.7
04	87	10.5	11.7	11.8	10.9	11.5	13.8	11.8	11.3
05	86	10.3	11.4	11.3	10.3	10.9	13.5	11.5	11.1
06	85	9.8	10.8	10.7	9.7	10.4	12.9	11.0	10.6
07	83	9.4	10.3	10.0	9.1	9.7	12.4	10.6	10.2
08	86	8.7	9.5	9.3	8.5	9.1	11.4	9.7	9.4
09	86	8.3	9.1	9.3	8.2	8.9	10.9	9.3	9.0
10	92	8.0	8.8	9.1	7.8	8.6	10.5	9.0	8.6
11	94	7.8	8.5	8.6	7.6	8.2	10.2	8.7	8.4
12	95	7.5	8.2	8.3	7.6	8.0	9.9	8.4	8.1
13	92	7.3	8.1	8.1	7.6	7.9	9.6	8.2	7.9
14	92	7.5	8.4	8.6	8.2	8.3	9.9	8.4	8.1
15	92	7.9	8.8	9.0	8.7	8.8	10.4	8.9	8.6
16	91	8.6	9.6	9.9	9.8	9.7	11.3	9.7	9.3
17	92	9.4	10.6	10.9	10.8	10.7	12.3	10.5	10.1
18	93	10.1	11.4	11.7	11.7	11.5	13.2	11.3	10.9
19	93	10.7	12.1	12.7	12.4	12.3	14.0	12.0	11.5
20	91	11.2	12.6	13.2	12.8	12.8	14.6	12.5	12.1
21	91	11.5	12.8	13.2	12.6	12.8	15.0	12.8	12.4
22	91	11.6	12.8	13.1	12.4	12.7	15.2	13.0	12.5
23	91	11.7	12.9	12.9	12.1	12.6	15.3	13.1	12.6
24	91	11.5	12.6	12.7	11.7	12.3	15.0	12.8	12.4
Total	2163								
Overall Mean Speed		9.7	10.7	10.9	10.2	10.6	12.7	10.8	10.5

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The mean α (10-VRD) for the study period at S-01 is 0.05. Thus the HUBXP technique, using α = 1/7, causes a 20 percent error in estimating the mean rotor disk winds. Note that α's determined from only 4 or 5 days of tower data resulted in mean speeds within 3 percent of VRD.*

The diurnal variation of α is much different than over flat terrain (Figure 4). The highest α occurs in late afternoon or early evening, lowest values near sunrise. In flat terrain, however, highest α's occur about midnight, lowest values in the early afternoon (Hiester and Pennell, 1981).

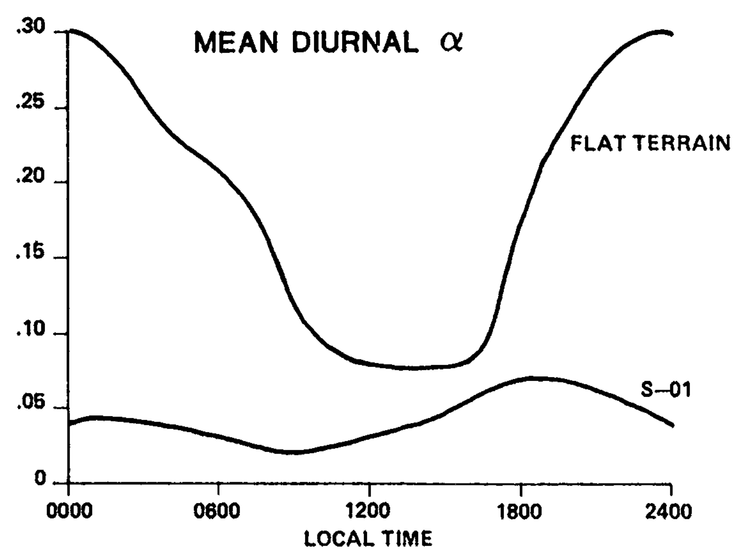

FIGURE 4. MEAN DIURNAL α (10-VRD) AT S-01, SUMMER 1980 AND FOR TYPICAL FLAT TERRAIN.

*However, the variability in individual VRD estimates are not at all described by using a single derived α value (see Table 3.4.1).

Available Power in the Wind

Site evaluations frequently include available wind power as a measure of the wind resource. The mean power is computed from the formula

$$\overline{P} = 1/2\ \overline{\rho V^3}$$

where $\overline{P}$ is the mean power, $\overline{\rho V^3}$ is the mean product of air density (ρ) and the cube of the wind speed.

Considerable differences result when the six different estimates of rotor disk winds are applied (Table 2).

TABLE 2. MEAN AVAILABLE POWER (Wm^{-2}) AT S-01, SUMMER 1980

Type of Wind Speed	Power
VRD	978
V10	739
V60	1086
HUBXP	1666
HUBK1	1037
HUBK2	931

Not unexpectedly, HUBXP is completely off the mark, being 70 percent too high. V10 is the second poorest estimator, being 25 percent too low. The other techniques are all within 10 percent of the measured value (VRD).

Frequency Distributions of α

There is a considerable range in α-values at S-01 between 10 m and VRD (assumed height of 60 m), as shown in Figure 5. Extreme values are less frequent with higher wind speeds.

The negative shear can be particularly pronounced between 60 and 90 m. Between these two levels α is often below -0.50 and has been measured to be below -1.00 under strong wind conditions (Figure 6).

Physical interpretation of these data is difficult. Apparently there is flow decoupling or flow separation; in other words, a mixing depth well below 100 m with surface winds of 10-15 mps. Onsite acoustic sounder observations during early 1981 support this conclusion.

Frequency Distributions of Wind Speed

The frequency distributions of wind speed for the study period at S-01 are presented in Figure 7. Category breaks for wind speed are critical values of the BWT 2560 performance curve:

Category	Classification
0 - 6.3 mps	below cut-in
6.3 - 9.4 mps	cut-in to half-rated power
9.4 - 12.2 mps	half-rated power to rated power
12.2 - 26.9 mps	rated to cut-out
>26.9 mps	above cut-out

HUBK1, HUBK2, and V60 are very close to the true values. V10 is less accurate, and HUBXP grossly shifts the frequency distribution towards the higher wind speeds. It overestimates the frequency of winds above rated speed by more than 20 percent.

BWT 2560 Power Output Simulations

Mean diurnal and overall capacity factors for a BWT 2560 are presented in Table 3. V60, HUBK1, and HUBK2 were clearly the best approximators of overall mean capacity factor at the two sites, with absolute errors ranging from 1-2 percent, relative errors from 1-3 percent.

V10 and HUBXP were far worse. The absolute error using V10 was 6 percent, the relative error 11 percent. The absolute error using HUBXP was 13 percent, or a relative error of 20 percent. Only VRD accounts for diurnal changes in the wind shear profile characteristics. Thus there is some diurnal fluctuation in the degree of error caused by the other techniques.

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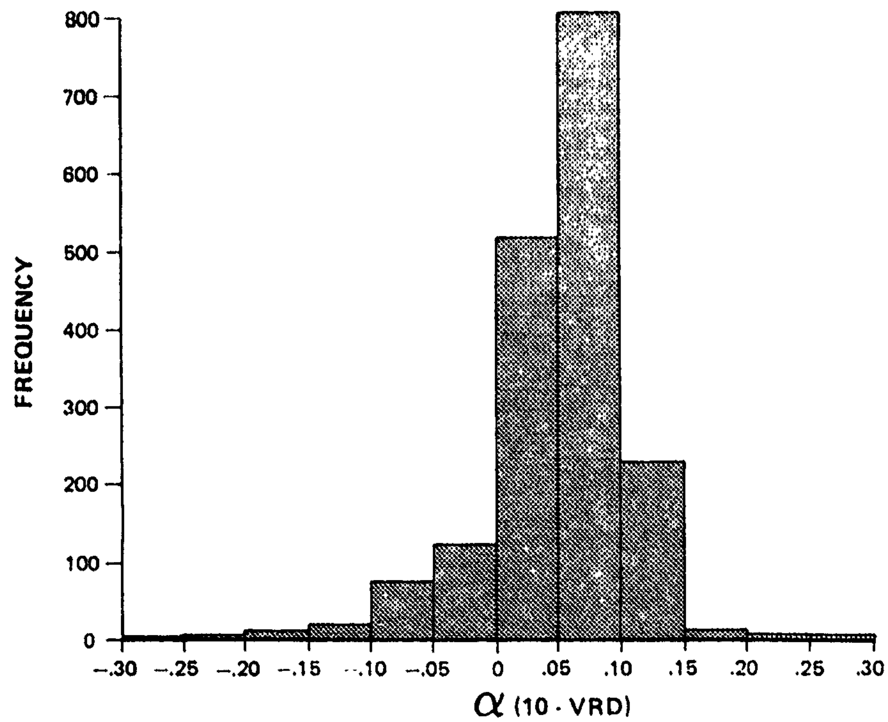

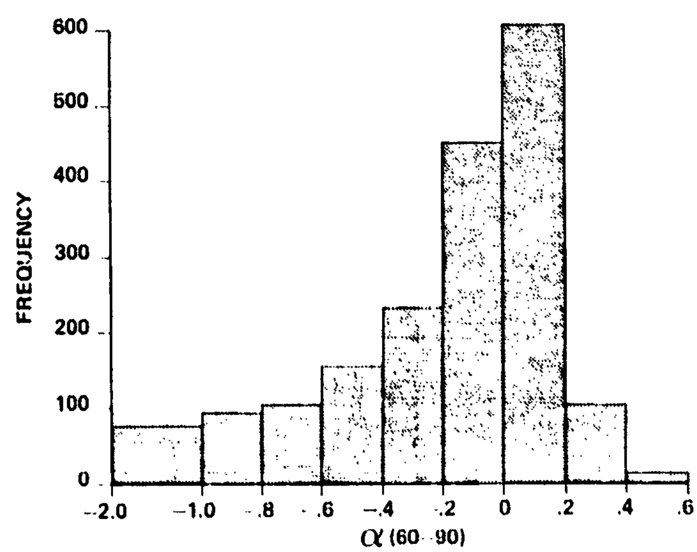

FIGURES 5, 6. FREQUENCY DISTRIBUTION OF α (10-VRD) AND α (60-90) AT S-01, SUMMER 1980. ONLY WINDS ABOVE CUT-IN SPEED ARE CONSIDERED.

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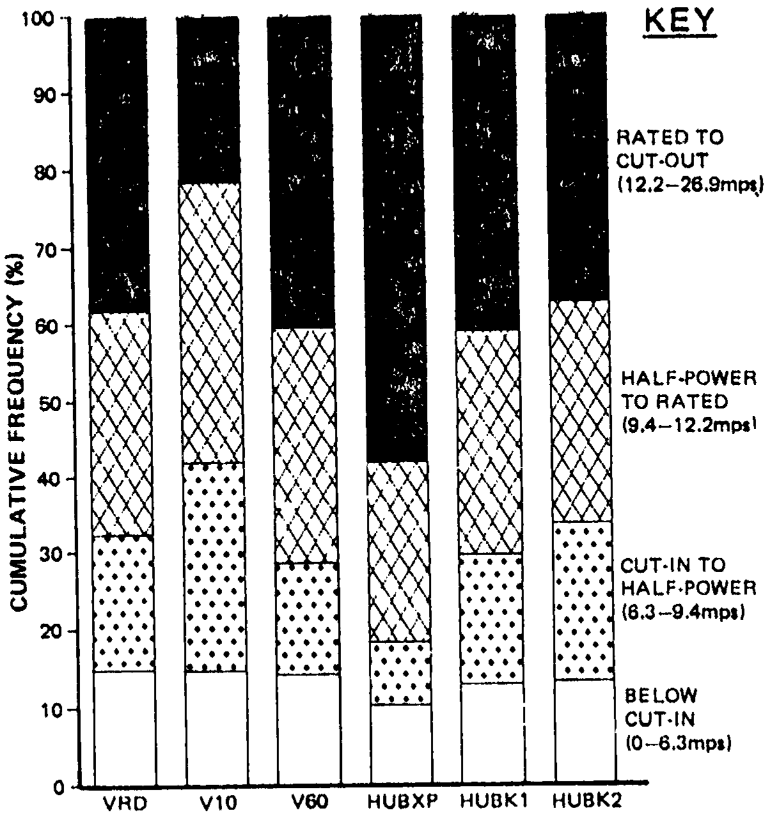

FIGURE 7. S-01 WIND SPEED FREQUENCY DISTRIBUTION, SUMMER 1980.

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TABLE 3. MEAN DIURNAL CAPACITY
FACTORS (PERCENT) FOR A BWT 2560 AT S-01,
SUMMER 1980

Hour (PST)	VRD	V10	V60	HUBXP	HUBK1	HUBK2
01	79	73	81	89	81	79
02	77	72	79	88	80	78
03	76	70	78	86	79	76
04	74	67	75	84	75	73
05	69	64	71	81	73	70
06	65	59	65	78	70	66
07	59	55	60	75	65	62
08	54	49	56	69	59	56
09	51	44	54	68	56	52
10	48	40	53	65	52	49
11	43	37	47	63	49	45
12	40	33	43	61	45	41
13	38	32	40	58	42	37
14	42	30	46	60	44	40
15	49	37	53	65	50	46
16	60	45	62	72	58	54
17	70	54	71	80	67	64
18	78	63	79	86	76	72
19	84	70	86	90	82	79
20	86	76	88	91	85	82
21	85	77	88	92	85	83
22	84	78	85	93	85	83
23	84	78	85	92	86	84
24	80	75	82	91	83	80
Overall	66	58	68	79	68	65

What do these errors really mean with respect to the cost of energy? A formula for computing energy cost is:

$$COE = \frac{IC \cdot FCR + LF1 \cdot AOM + LF2 \cdot AFC}{AEP}$$

where

COE = cost of energy, e.g., ¢/kWh
IC = initial system cost
FCR = levelized fixed charge rate
AOM = annual operation and maintenance costs
LF1 = levelizing factor for O+M costs
LF2 = levelizing factor for fuel costs
AFC = annual fuel costs (equals zero for wind turbines)
AEP = anticipated annual energy production

Thus the cost of energy is inversely proportional to the energy production.

Relative errors greater than 10 percent will certainly be significant. Thus using the 10-m wind data alone (V30) or with a 1/7 power law (HUBXP) would have caused significant errors. The 1/7 power law in particular gave very poor results, and the cost of energy calculated on that basis would be 20 percent too low.*

Comparison of Winter and Summer Vertical Profiles

The mean vertical profiles at both sites change seasonally with similar wind speeds and directions (Figure 8). The mean α (10-VRD) was .03 higher in winter than summer for westerly winds of power-producing strength. This seasonal fluctuation results from the different wind-driving forces of the two seasons--mesoscale sea breeze in summer, synoptic in winter.

Also, strong winds blow from several directions during winter. Additional errors would thus be introduced if a summer α were applied to 10-m data from other seasons and/or wind directions.

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Considerable errors in wind speed and power generation estimates were found at Site S-01 with certain techniques for estimating effective rotor disk winds, as summarized below (Table 4). In particular, the 1/7 power law (HUBXP) applied to 10-m data caused very large errors and should not be used.

*The study period comprised only the summer season, and thus does not simulate annual energy production. The concept is still quite valid, though.

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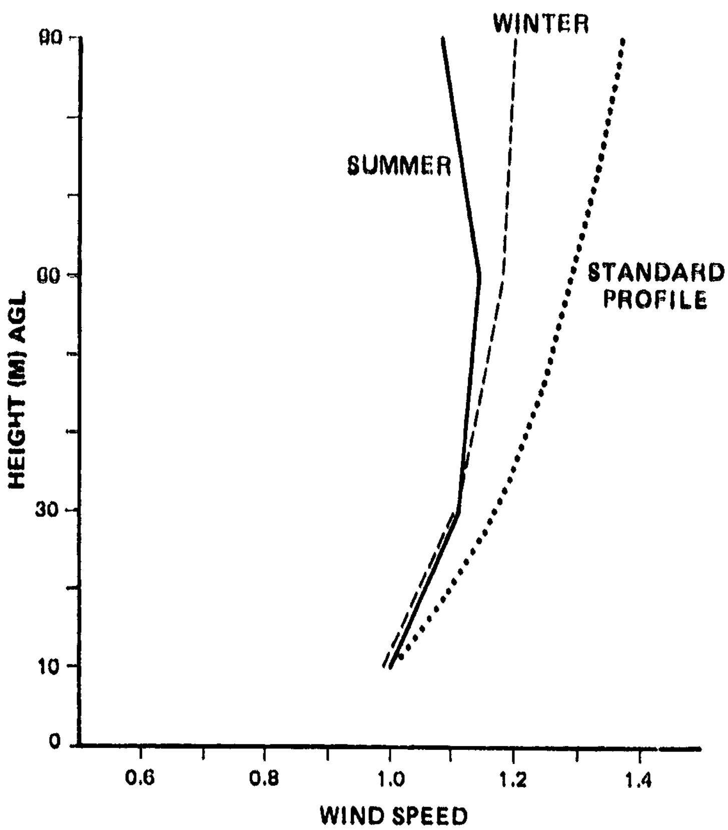

FIGURE 8. MEAN PROFILE CHARACTERISTICS AT S-01 FOR WESTERLY WINDS ABOVE CUT-IN SPEED. CURVES ARE NORMALIZED TO 10-M SPEED.

TABLE 4. SUMMARY OF ERRORS (IN PERCENT) IN SPECIFYING WIND ENERGY PARAMETERS CAUSED BY DIFFERENT MONITORING STRATEGIES[a]

	V10	V60	HUBXP	HUBK1	HUBK2
Mean speed[b]	-9	3	20	2	-1
Mean power[b]	-24	11	70	6	-5
Percent hours at rated power[c]	-17	2	20	3	-1
Mean capacity factor[b]	-12	3	20	3	-1

[a]VRD used as control variable

[b]Relative errors (actual error divided by VRD mean)

[c]Actual percentage error

In conclusion, the 60-m (hub height) wind was the most accurate technique, even though S-01 had a mean reversal in shear with maximum mean winds at that level. In practice one would probably not measure only at this level to estimate the wind resource, but these results do imply hub height data should be adequate for estimating the overall performance of large wind turbines.

While the 10-m wind data alone were not very accurate, the addition of even a few days' worth of vertical profile measurements greatly improved the estimates. However, one must be very careful about making generalizations from these results. (Only one season with one dominant wind direction was considered here.) The amount of random data needed to predict the vertical profile characteristics with sufficient confidence will surely vary from site to site and is hard to specify in advance. Further, intermittent monitoring strategies (e.g., kites, Doppler acoustic sounder) run a high risk of missing extreme conditions, such as severe wind speed and/or direction shears.

By far the most important conclusion of this study is that gross errors in estimating rotor disk wind speeds and energy production can result if measurements are limited to the 10-m level. As pointed out earlier, most wind energy sites will be in complex terrain, and it is absolutely crucial to obtain measurements up to at least hub height and preferably to the top of the rotor disk.

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