Increasing turbine dimensions: impact on shear and power

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Abstract. As wind turbine average hub-height \( H \) and rotor diameter \( D \) grow, it is assumed that the benefit derived from larger swept areas and higher wind speeds at higher altitudes will outweigh any increase in fatigue loading due to higher shear and manufacturing/installation costs. The impact of increasing wind turbine \( H \) and \( D \) on power production and the occurrence of extreme positive and negative shear is examined using high-resolution simulations with the Weather Research and Forecasting (WRF) model over Iowa. Three wind turbine scenarios are considered; S#1: \( H=83 \text{ m}, D=100 \text{ m} \); S#2: \( H=100 \text{ m}, D=100 \text{ m} \) and S#3: \( H=100 \text{ m}, D=133 \text{ m} \). Increasing \( H \) from 83 m to 100 m while maintaining \( D=100 \text{ m} \) increases power by 16% relative to scenario 1. Increasing \( D \) to 133 m from 100 m with \( H=100 \text{ m} \) doubles the power output compared to S#1. Extreme shear across the rotor plane (shear exponent \( \alpha > 0.2 \) or \( \alpha < 0 \)) is frequently observed, but only modestly impacted by the changes in wind turbine dimensions. Thus, the increase in power output from increasing \( H \) and \( D \) to these levels seems to incur little penalty in terms of increased occurrence of high positive or negative shear.

Keywords: Wind speed profiles; shear; turbine size; WRF

1. Introduction

In both the USA and Europe there is a continued tendency towards increasing wind turbine (WT) hub-height \( H \) and rotor diameter \( D \) [1-4]. Prior to 2007, \( H \) and \( D \) increased at about the same pace such that they continued to be approximately equal (Figure 1). Recently, the increase in \( D \) has started to outgrow that in \( H \). This tendency towards larger wind turbines has been amplified by installation of 22 GW offshore (of 183 GW total installed with capacity) in Europe with turbines that are typically larger (5-6 MW vs the average of 2.6 MW) [3]. In 2019, the average capacity of installed wind turbines offshore in Europe in 2019 was 7.8 MW compared with the installed average (onshore/offshore) of 4.4 MW and the rated capacity of new onshore turbines of 3.1 MW. WT deployed in the USA during 2019 had an average hub height of 90 m and a rotor diameter of 121 m, which are both marked increases from comparable values in 2015 of 82 m and 102 m, respectively [5]. Within the surface-layer (lowest ~10% of the atmospheric boundary-layer) the average wind speed profile is frequently well-described using the stability-corrected logarithmic profile [6], which implies increasing wind speed and thus power with height, and infrequent occurrence of large fatigue loading due to high positive values of shear or the occurrence of negative shear across the rotor plane. However, as rotor tip heights have extended beyond 100 m height it can be argued that a logarithmic profile cannot be applied to model wind speed change with height for estimating power production [7]. Modifying the logarithmic profile by a stability
correction [8] may be insufficient and more complex formulations of the wind speed variation with height may be needed [9].

Turbulence intensity and wind shear are the two parameters for inflow conditions that wind turbine loading are most sensitive to, particularly for ultimate loads [10]. Further, low-level jets (LLJ) are typically assumed to be centred at heights above 300 m a.g.l. [11], but within the U.S. Great Plains they are frequently observed at heights that impinge on wind turbine rotor planes [12], and a recent study has demonstrated their prevalence at wind turbine relevant heights over the Midwest including Iowa in spring [13]. Thus, it is not clear whether increasing wind turbine dimensions will yield expected power and/or how shear across the rotor plane will change.

![Figure 1](image1.png)

**Figure 1.** Mean hub-height ($H$, in m) (left), rotor diameter ($D$, in m) (right) and rated capacity (in MW, right, symbol size) for all wind turbines installed in each calendar year in the European Union (EU) and United States of America (USA) [3, 4]. The line in the left panel also shows annual mean capacity factors in the US from 2008 onwards [4].

2. **Objectives**

   The objective of the research is to assess how current trends in increasing $H$ and $D$ impact power production and the occurrence of extreme shear across the rotor plane. Iowa was selected for this analysis because it has approximately 5,400 WT with installed capacity of over 10 GW [14] and had the highest reported vertical wind shear in an early analysis of five Midwest wind projects [15].

3. **Methodology**

   Simulations were performed using the WRF model (v3.8.1) for nine months from December 2007 to August 2008 [16-18]. The simulations were conducted within lateral boundary conditions from ERA-Interim reanalysis and using physics settings detailed in [16, 19]. The outer domain comprises 149 by 149 12-km grid cells and encompasses much of the US Midwest, and the inner domain, centred over Iowa, comprises 246 by 204 4-km grid cells (Figure 2). The simulations were run with 57 vertical levels, ten of which are below 180 m (Figure 3). Wind speed components are output and analysed at 10 minute intervals. Analyses presented herein focus on a transect at a latitude of 43°N across the northern portion of Iowa extending over a region of relatively high installed capacity and a marked gradient in topographic complexity (Figure 2). Three scenarios of WT dimensions are employed (Figure 3):

   S#1: $H=83$ m, $D=100$ m
   S#2: $H=100$ m, $D=100$ m
   S#3: $H=100$ m, $D=133$ m.
S#1 represents the mean of currently installed WT, while S#2 is intended to represent the same turbine with a taller tower and S#3 a larger rotor on the taller tower. The three scenarios are illustrated in Figure 3 that also shows the monthly deviation of the mean heights of each model level that arise because WRF employs a terrain-following, dry hydrostatic-pressure coordinate system. This results in a weak seasonal cycle in terms of the mean heights above ground level (a.g.l.) for each level, with higher heights during the warmer months. There is modest variability in the second model level (mean 33±1 m) but this variability increases with height such that the mean monthly height above ground is 168±9 m at level 10. This variation makes a small but non-zero impact on the model-derived rotor swept area month by month (shown as ΔArea in Figure 3d).

Figure 2. Map of the terrain elevation in the inner WRF domain, along with the state boundaries and the location of the four sites (magenta) on the transect at 43°N latitude across the north of Iowa.

Figure 3. Mean heights (a.g.l.) of the lowest ten model levels in each month as derived from the modelled sigma coordinate system (black lines). (a)-(c) The coloured lines show the hub-height and top and bottom of the rotor plane for each of the three wind turbine scenarios (i.e. variations of $H$ and $D$), while the dashed lines and filled colours show the actual heights from which output is used. Panel d) summarizes the variation in the area of the rotor plane by month due to the variation in mean model level height above ground.
To calculate power production, the rotor equivalent wind speed (REU) is used [20]:

\[
REU = \left( \sum_{i=1}^{n} U_i^3 A_i / A \right)^{1/3}
\]  

(1)

Where:

\[
A_i = \int_{z_i}^{z_{i+1}} c(z)dz
\]

(2)

and

\[
c(z) = 2\sqrt{R^2 - (z - H)^2}
\]

(3)

Where \( nh \) is the number of measurement heights across the rotor plane, \( U_i \) is the wind speed measured at the \( i \)th height, \( A \) is the swept area of the rotor, \( A_i \) is the area of the \( i \)th rotor segment, \( z_i \) is the height of the \( i \)th segment separation line (1 is the bottom layer), \( R \) is the rotor radius and \( H \) is the hub-height.

The normalized power ratio \( P_{nx} \) for each wind turbine scenarios is calculated relative to power output in scenario S#1 such that e.g. for scenario S#x:

\[
P_{nx} = (A_2 \sum_{i=1}^{n} REU_{3,i}) / (A_1 \sum_{i=1}^{n} REU_{3,i})
\]

(4)

\( REU_{3,i} \) is the mean of the cube of the 10-minute rotor equivalent wind speeds in each month with \( n \) 10-minute periods.

Non-transient wind shear (i.e. timescales of >12 seconds) is analysed in accord with IEC 61400-3 [21]. Hence, the shear exponent \( \alpha \) across the rotor plane is defined as:

\[
U_1 = U_2 \left( \frac{z_1}{z_2} \right)^{\alpha}
\]

(5)

and calculated for each wind turbine scenario using wind speeds and model level heights derived from output from WRF every 10 minutes:

\[
\alpha = \log \left( \frac{U_1}{U_2} \right) / \log \left( \frac{z_1}{z_2} \right)
\]

(6)

Where \( U_1 \) is the wind speed at height \( z_1 \); the top of the rotor plane and \( U_2 \) is the wind speed at height \( z_2 \); the bottom of the rotor plane.

If \( \alpha < 0 \) or \( \alpha > 0.2 \) then shear lies outside the normal operating range. The frequency of negative shear (\( \alpha > 0.2 \)) and the frequency of extreme positive shear (\( \alpha > 0.2 \)) during power producing wind speeds (4-25 ms\(^{-1}\)) are expressed in normalized terms (i.e. the fraction of the time on which it occurs in a given wind turbine scenario) relative to the frequency of occurrence in scenario #1 such that e.g. for scenario #x:

\[
S_{f,x} = f(\alpha_x) / f(\alpha_1)
\]

(7)

The magnitude of wind shear across the rotor plane (\( S_m \), in ms\(^{-1}/m \)) for the three scenarios is calculated from:

\[
S_m = (U_2 - U_1) / (z_2 - z_1)
\]

(8)

4. Results

4.1 Rotor equivalent wind speeds and power

Rotor equivalent wind speeds (REU) exhibit clear seasonality with higher monthly mean values and a higher frequency of power producing wind speeds in winter/spring than summer. Monthly histograms of 10-minute wind speeds show slightly flatter probability distributions in the winter/spring months with more peaked distributions and lower mean wind speeds during summer. However, there are periods with high rotor equivalent wind speeds in all months. April and January experienced highest mean monthly wind speeds, and April exhibited a particularly large fraction of 10-minute periods with REU above rated for currently installed WT (Figure 4). The three wind turbine scenarios exhibit relatively similar probability distributions of REU, consistent with the relatively modest changes in wind turbine hub-height and rotor diameter, but it is noteworthy that the probability distributions are broader and have
heavier right tails in the scenarios with the large WT dimensions (Figure 4). Comparing the three wind turbine scenarios, the mean REU for S#1 is 0.3-0.5 m/s lower than in S#2 and S#3 (Figure 4) because of the lower hub-height/smaller rotor diameter (Figure 3).

Power production scales with the cube of the rotor equivalent wind speed ($REU^3$) and linearly with the rotor area. The increase in $H$ from 83 m to 100 m in scenario S#2 while holding $D$ constant at 100 m results an approximately 16% increase in power (i.e. $P_{S2} \approx 1.156 - 1.160$ (Table 1)). Increasing $H$ to 100 m and increasing $D$ to 133 m (i.e. scenario S#3) results in a doubling of power (i.e. $P_{S3} \approx 2.00$), which is a greater increment than would be anticipated either from the increase in rotor swept area ($A_3/A_1 = 1.77$) but is consistent with the cross product of the benefit from the increased swept area (1.77) and that from increasing the hub-height (1.16). There is very little spatial variability across the four locations on the transect in terms of the mean power gains from the large wind turbines, but there is some weak evidence of a small west-east gradient in the normalized power ratios (Table 1).

Table 1. Mean ratio of total power and the frequency of extreme positive shear ($\alpha > 0.2$) from each wind turbine scenario to scenario S#1 for all 10-minute periods with power producing REU during December 2007-August 2008. The values shown denote the mean of the normalized ratios computed from the monthly mean values plus/minus one standard deviation.

| Scenario | $H$ (m) | $D$ (m) | Location 1: 43°N 95°W | Location 2: 43°N 94°W | Location 3: 43°N 93°W | Location 4: 43°N 92°W |
|----------|--------|--------|---------------------|---------------------|---------------------|---------------------|
| S#1 Power ratio | 83     | 100    | 1                   | 1                   | 1                   | 1                   |
| S#2 Power ratio | 100    | 100    | 1.161±0.021         | 1.160±0.021         | 1.156±0.022         | 1.156±0.021         |
| S#3 Power ratio | 100    | 133    | 2.007±0.032         | 2.004±0.038         | 2.002±0.035         | 2.001±0.030         |
| S#1 Shear ratio | 83     | 100    | 1                   | 1                   | 1                   | 1                   |
| S#2 Shear ratio | 100    | 100    | 0.970±0.060         | 0.979±0.055         | 1.001±0.042         | 0.979±0.032         |
| S#3 Shear ratio | 100    | 133    | 0.985±0.018         | 1.002±0.019         | 0.998±0.060         | 0.993±0.019         |

Figure 4. Top: Scatterplots of monthly mean REU for wind turbine scenarios S#2 and S#3 versus S#1 at location 43°N, 95°W. Symbol colours and the numbers denote calendar month where 0=Dec, 1=Jan etc. Bottom: Histograms of monthly 10-minute REU discretised in 2 m/s wind speed classes as sampled by the three wind turbine scenarios. Colours used are as described in the upper legend. The REU shown are for the most westerly location (43°N, 95°W) but the change in REU is consistent between the sites.
There is some month to month variability in the normalized ratios of power production from wind turbine scenarios #2 and #3 relative to scenario S#1 (Figure 5). Generally, the increase in rotor diameter and/or wind turbine hub-height yields greatest enhancement in power during the summer months. Specifically, the greatest increase in \( P_{r2} \) is observed in August at all four locations on the transect (Figure 5). The largest discrepancies in power gains from the deployment of the larger wind turbines (i.e. \( P_{rx} \)) between the transect locations are observed during the winter months (December, January, February). During these winter months the two most westerly sites have \( P_{r2} \) that are \( \sim 3\% \) higher than the two easterly sites, this implies some limited degree of spatial variability in the benefits to be gained from deployment of wind turbines with higher hub-heights or rotor diameters. The lowest \( P_{r2} \) at all four locations is found in May (Figure 5) likely due to the comparatively low wind shear during this month.

**Figure 5.** Mean monthly power ratios \( (P_{rx}) \) at each location on the transect. Recall Power ratios \#X \( (P_{rx}) \) are computed as the ratio of power from scenarios S#2 and S#3 to that from scenario S#1 (from equation 4 where power is computed as the product of the area and \( R_{REU} \)).

### 4.2 Shear across the rotor plane

The shear exponent across the rotor plane (\( \alpha \)) is frequently greater than 0.2 at all four locations on the transect irrespective of the wind turbine scenario under consideration (Figure 6). This is consistent with previous research that has indicated a high frequency of extreme shear in Iowa [15], and evidence of a high frequency of rotor-relevant LLJ in Iowa [13]. The mean occurrence of \( \alpha > 0.2 \) for the three wind turbine scenarios at the four locations on the transect is S#1=48.1\%, S#2=48.9\%, S#3=48.9\%. The mean and standard deviation computed from the nine monthly frequencies of 10-minute shear exponent values in excess of 0.2 show only a small gradient from west to east and also a slight decrease in variability along the gradient. The mean and standard deviation are thus: 48.2±10.1\%, 47.9±9.0\%, 49.6±6.2\%, 50.33±6.3\% moving west to east across the four locations.

It is important to acknowledge that modelled wind shear is sensitive to the land surface model used in WRF and the land cover datasets employed [22]. The implied high frequency of high positive shear is consistent with experimental data from a summertime campaign at the SWiFT facility in Texas that indicated a modal value of shear exponent of \( \alpha > 0.35 \) [23], and that similarly high frequencies of extreme shear have been reported across the rotor plane at coastal sites [24]. Further, WRF simulations over the Southern Great Plains also revealed periods with very high shear exponents particularly over night [25].
There is a noticeable decrease in the frequency of occurrence of extreme positive shear at all four locations during May, June and July (Figure 6). The mean frequency of occurrence of $\alpha > 0.2$ during these months is: 41.5%, 41.5% and 43% for the three wind turbine scenarios. Conversely, extreme shear is most frequent in December and January (S#1: 58.8% and 60.3%, respectively). The consistency across the four locations suggests that the drivers of high shear values are regional. Increasing the hub-height from 83 m to 100 m or increasing both the rotor diameter and hub-height has a negligible impact on the frequency of occurrence of high shear across the rotor plane.

![Figure 6](image)

**Figure 6.** The frequency of occurrence of high shear ($\alpha > 0.2$) at each location on the transect (recall all locations are at a latitude of 43°N and vary only by longitude (y-axis)) by month for all three wind turbine scenarios (denoted by the different coloured circles). The size of the circles shows frequency of occurrence of $\alpha > 0.2$ and ranges from 33% to 66%. The numbers in the symbols indicate the frequency of high shear in S#1.

Negative shear is considerably less common. Values of $\alpha < 0$ occur with a mean frequency of occurrence in S#1 across the four locations of 2.8%, 2.8%, 2.8% and 2.4% from west to east. Negative shear occurs in each month but at low frequency (i.e. in about 40 to 240 10-minute periods per month for wind turbine S#1, Figure 7). There is no obvious seasonality to, or locational dependence on, the occurrence of negative shear. Increasing the hub-height (S#2) increases the frequency of occurrence of negative shear. Increasing both the hub-height and the rotor diameter (S#3) results in only minor increases in the occurrence of negative shear across the rotor plane in comparison to S#1 (Figure 7).

The joint probability distribution of hub-height wind speed and shear exhibits variability across the transect, as does the probability distribution of shear exponents. The month of April has the largest differences across the transect, and is also the month with the highest mean wind speed. As shown in Figure 8 and indicated above, high shear ($\alpha > 0.2$) occurs more frequently at power producing wind speeds than does negative shear (<1% of any joint frequency of wind speed discretized in 1 ms$^{-1}$ bins with shear discretized at 0.01 ms$^{-1}$/m). However, negative shear occurs at all sites, not just in April but in every month. It occurs most often when hub-height wind speeds are less than 10 ms$^{-1}$. Negative shear is also most frequent in S#2.
5. Conclusions

There is a continued tendency towards increasing hub-height ($H$) and rotor diameter ($D$) in order to maximize the rotor equivalent wind speed and swept area and hence power output from wind turbines (WT). The impact of increasing WT dimensions on both power and shear is examined using output from high-resolution simulations with WRF over a nine-month period from December 2007-August 2008. The analysis focuses on a region of the US known to exhibit complex and highly sheared wind speed profiles and high wind resources; the US state of Iowa.

Three realistic scenarios of wind turbine hub-height and rotor diameter are considered in terms of their impact on likely power production and potential for extreme shear and resulting mechanical loading. Scenario S#1 represents the mean of currently installed wind turbines: $H = 83$ m, $D = 100$ m. In scenario S#2: $H = 100$ m, $D = 100$ m while in scenario S#3 $H = 100$ m, $D = 133$ m. The ratio of power for scenarios S#2 and S#3 to that in S#1 indicates power is enhanced by a mean of 16% by increasing $H$ in (S#2) but a much greater benefit in terms of power is gained from also employing larger $D$ (S#3) which almost doubles the power compared to S#1. The overall benefit in S#3 in terms of power production is consistent with industry trends towards increases in both $H$ and $D$.

The frequency of high shear ($\alpha > 0.2$) is greater than 33% in every month and scenario, increasing during the winter. Differences in the frequency of high shear exponent between the scenarios is small. The number of negative shear events is low (<8.5%) in any month, even in the two scenarios with higher $H$ and $D$. Based on these WRF simulations, for the US state of Iowa, there appears to be only a small penalty in terms of increased occurrence of high positive or negative shear occurrence from increasing hub-height or increasing the size of the rotor plane such that the top tip extends to over 200 m. The inference is that deployment of larger turbines will lead to a substantial increase in power production with only a small increase in the conditions that lead to higher mechanical loading on the rotor plane [10].

Analyses of WRF output across the Iowa transect indicate relatively modest spatial variations in shear exponents. Future research could explore microscale variability in wind shear under specific mesoscale forcing using WRF-LES [26] but is currently not tractable for the large domain and long duration simulations presented herein.
Figure 8. Analysis of shear from April 2008 for four locations on a west-east transect across northern Iowa. For each location, the top sub-panels show a histogram of the 10-minute values of $\alpha$ for the heights across the rotor plane for each wind turbine scenario. The red lines indicate two thresholds for $\alpha = 0$ and 0.2. The bottom sub-panels show the joint probability distribution of the 10-minute values of shear magnitude across the rotor plane and hub-height wind speed for each wind turbine scenario. The title above each lower frame is the fraction of 10-minute periods when the absolute value of $\alpha$ exceeded 0.2.

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