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Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand

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Abstract

The ability of wind power to reliably contribute energy to electricity networks is directly related to the characteristics of the wind resource. An analysis of the characteristics of the wind power resource of the United Kingdom has been carried out, based on modelling of hourly observed wind speed data from 66 onshore weather recording sites for the period 1970–2003. Patterns of wind power availability are presented, with the data demonstrating that the output from large-scale wind power development in the UK has distinct patterns of monthly and hourly variability. The extent and frequency of high and low wind power events is assessed, and wind power data are matched with electricity demand data to examine the relationship between wind power output and electricity demand. It is demonstrated that wind power output in the UK has a weak, positive correlation to current electricity demand patterns; during peak demand periods, the capacity factor of wind power in the UK is around 30% higher than the annual average capacity factor. Comments on the relevance of these findings to modelling the impact of wind-generated electricity on existing electricity networks are given.
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JEL classification: Q40; Q42

Keywords: Wind generation; Electricity; Variability

1. Introduction

The United Kingdom government has implemented market measures designed to accelerate the development of renewable electricity generating systems, with a target of 10% of UK electricity being delivered by renewables by 2010, a recent extension of the renewable obligation certificate (ROCs) mechanism to support renewable electricity generation of up to 15% of total demand by 2015, and an aspirational target of 20% renewable electricity by 2020 (Barber, 2005). It is anticipated that wind power, despite its current modest contribution towards meeting the UK electricity demand of 0.49% (DUKES, 2005), will be the dominant source of renewable electricity by 2010 (Mott Macdonald, 2003).

The ability of wind power to reliably contribute to UK electricity supplies is fundamentally related to the characteristics of the UK wind resource, and how characteristics such as seasonal weather patterns correlate with electricity demand. The degree of variability of wind power output has implications for the additional reserve requirements of the network (Holttinen, 2003; Ilex, 2002; Mott Macdonald, 2003), particularly during periods of high electricity demand.

The first part of this paper presents the results of an analysis of wind power output modelled from 34 years of hourly wind speed data from up to 66 onshore wind recording sites around the UK. From this extensive dataset, long-term variability in wind power output, together with seasonal patterns of wind power availability, have been identified. Secondly, modelled wind power output data is matched to electricity demand data at a 1-h timestep, allowing the longer-term relationship between electricity demand and wind power availability to be determined, together with the relationship between rare, extreme wind events and electricity demand levels. This paper offers concluding comments on the importance of understanding the characteristics of wind power for energy modelling purposes.

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doi:10.1016/j.enpol.2005.10.003

2. Data sources and data modelling

Surface wind speed observations recorded by the UK Met Office were used as the basis for modelling hourly wind power output. Previous authors have noted the preference for using actual wind turbine or wind farm output data for analysis purposes (cf. Holttinen, 2003), recognising that there will be some difference between the observed and modelled wind output data.

While acknowledging this concern, the potential dataset available for actual wind power output in the UK is limited by both geographical extent and the number of years the wind turbines have been installed at the different sites. By utilising the observed wind speed dataset for the UK, a vastly superior geographical representation of wind diversity around the UK is possible compared to the limited geographic distribution of observed measurements. Furthermore, observed wind speed data extends the period of the dataset far beyond that available from wind farm operations, providing greater confidence that the results will include low-frequency, high-magnitude climate events such as extended high or low wind speed events that may not have occurred within the timeframe of wind power operations in the UK. Given the focus of this research on long-term trends and broad geographical representation, it is appropriate to base this analysis on historic wind speed observations.

2.1. Wind speed data and wind power modelling

Observed hourly wind speed measurements collected from 66 UK sites between 1970 and 2003 have been used to model wind power output from a hypothetical array of wind turbines located in all regions of the UK. All wind speed recording sites were operated by the UK Met Office, and the wind speed data were obtained from the UK Met Office and British Atmospheric Data Centre.

Sites were selected on the basis of the length and completeness of the hourly wind speed record, the location of the site (coastal or inland), and to ensure an even regional representation of sites across the UK. Following site selection, the observed data were filtered to remove data points tagged in the original dataset as errors. As the wind speed data were collected close to the land surface, the reported data were corrected for the increased wind speed that would be encountered at turbine hub height. Each site was classified on the basis of being coastal, inland or island, and being located in southern, central or northern UK. Based on this categorisation, and by referring to the European wind atlas (Riso, 1989), the wind speed at each site was corrected to achieve a regionally appropriate annual capacity factor (CF), with the average of all the 66 sites achieving a predetermined UK average annual CF of 30% (except for validation purposes where a model dataset achieving a capacity factor of 35% was also assessed). The approach described here allows the impact of different assumptions regarding UK annual average capacity factor to be investigated.

The corrected hourly wind speed data were converted into power output using published power transform data for a Nordex N80 wind turbine (Nordex 2004). To allow the variability analysis to be carried out independent of assumptions regarding the installed wind power capacity, hourly power output figures were expressed as a percent of the rated capacity of the wind turbine (or hourly capacity factor).

The average wind power output per hour was then determined for each hour, using all sites for which valid wind speed data were recorded. Not all sites returned valid data for every hour in the study dataset—to maintain the broad geographic representation of the wind power output data, it was necessary to filter the data to ensure only those hours with a sufficient number of valid data sites were included in the final dataset. A minimum of 45 sites (of a possible 66) with valid wind speed data were required for that hour to be included in the final dataset, with each site contributing equally to the overall wind electricity output each hour (with no regional transmission constraints). At the completion of this process, the hourly wind speed dataset included over 15 million hours of wind speed measurements, representing the wind power output characteristics for an average of around 230,000 hours at each of the 66 sites.

2.2. Validation of the data treatment method

Validation of this data treatment compared two key features of recorded and modelled wind power time series; firstly, a comparison of wind power variability with observed data was carried out, while the second technique involved the comparison of annual capacity factor data from the UK wind farm output and the model dataset.

2.2.1. Comparison of wind power variability

The first validation of the wind speed data treatment used for this research was an analysis of the variability of the wind power time series. For this analysis, the average level of the UK wind power production was determined for each hour in the dataset, with each wind speed site contributing equally to the average result. The change in power output of this time series was determined over both a 1-h and 4-h timestep, and the standard deviation of the resulting time series was calculated.

Expressed as a percentage of the installed capacity of wind power, the standard deviation of the modelled wind power data was 3.2% at the 1-h-ahead time period, and 10% at the 4-h-ahead time period. These data compare favourably with those calculated for UK and Danish wind power output (Table 1).

The reported results for the model dataset suggest that the data treatment method has resulted in a wind power dataset with similar variability characteristics to observed datasets. Given that the model data results are equal to or

Table 1
Comparison of 1 and 4-h-ahead variability in wind power output

Data source	One hour ahead (%)	Four hours ahead (%)
NGC	3.1	6 (at 3.5 h timestep)
Danish wind data	3.0	10
Model data (this study)	3.2	10

Data presented is the standard deviation of the change in wind power output, expressed as a percentage of installed wind power capacity (source: Milborrow, 2001).

slightly greater than similar data calculated from actual wind power observations, the model wind power time series may be slightly persimistic with regard to the variability of the wind power.

2.2.2. Comparison of observed and modelled annual capacity factor

The second validation method used to assess the wind speed data treatment involved the comparison of observed and modelled annual capacity factor values, with similar data derived from the model wind power dataset (refer to Section 3.1 for a definition of capacity factor). The Digest of UK Energy Statistics provides annual capacity factor values calculated from the actual electricity production of wind farms in the UK for the period 1993–2003 (DUKES, 1998, 2004), and these data are compared against similar data calculated from the model dataset to examine the closeness of fit between the modelled and observed annual capacity factor values (Fig. 1).

Comparisons have been made assuming both a 30% and 35% long-term annual average UK capacity factor for the model dataset. There is a high degree of similarity between the observed and modelled annual capacity factor figures (assuming a long-term CF of 30%), with the pattern of variability being particularly similar from 1997 onwards (average CF values for the observed and modelled data series are identical for the period 1997–2003). This is likely to be a result of the increasing installed capacity of wind power, together with an increasing diversity in development sites, providing a more representative measure of the UK's annual average capacity factor.

From Fig. 1, it appears that a long-term annual CF of 30% for the UK provides a close approximation to the wind power output figures currently being reported in the UK. This estimate may need to be revised upwards in future years as a greater proportion of the UK's wind generating capacity is developed in higher wind areas.

The result of assuming a long-term CF of 35% is an annual CF pattern that closely matches that of the observed annual CF values, but overestimates the magnitude of these annual figures.

This second validation technique again suggests that the model dataset achieves a good approximation of the recorded annual capacity factor values for the UK; furthermore, it confirms the decision to assume a 30% capacity factor for the model dataset as being appropriate for the current level of wind power development.

3. Characteristics of the UK wind resource

The modelled wind power dataset for the UK has been analysed to identify the historic availability of wind power at a yearly, monthly and hourly timescales; a discussion of capacity factor is presented, with subsequent analyses being presented in terms of capacity factor.

3.1. Capacity factor

Capacity factor (or load factor) expresses the amount of electricity produced by an electricity generator as a percentage of the maximum theoretical production from the generator. There are many operational reasons why generators may operate at less than maximum output, including shutdown periods for maintenance (planned or unplanned), or simply through a lack of demand for electricity at certain times of the year.

Wind generators will require shutdown periods for maintenance; however, the main determinant of capacity factor for wind generators is the availability and speed of the wind. Wind generators typically operate below rated capacity for around 90% of all hours (site dependent); this mode of operation results in an annual average capacity factor for wind turbines substantially below that typically achievable for conventional generators.

There is an ongoing debate regarding the capacity factor of wind power in the UK. The reported annual capacity factor for the UK wind power has varied from 24% to 31%, with a long-term average of around 27% (DUKES, 1998, 2005); these reported figures include downtime due to maintenance, and forced outages due to mechanical failure. In contrast to these reported figures, recent studies (cf. Dale et al., 2004) have tended to use a long-term annual average capacity factor of 35%; this decision is likely based on the higher wind speeds, and hence capacity factors, that are expected from offshore wind power developments, and a bias towards future onshore wind power developments in higher wind speed regions such as Scotland. A pessimistic view of UK capacity factors for wind power has also been put forward by a number of authors, suggesting capacity factor figures of 25% and below (Royal Academy of Engineering, 2003; Sharman, 2005).

It is considered likely that the reported capacity factor of 27% for wind power in the UK will rise over time as future developments concentrate on higher wind resource regions such as Scotland and offshore. The results of the data validation process (Section 2.2.2) suggest that a 30% capacity factor is generally representative of the current level of wind power development in the UK. However, this may need to be revised upwards once significant wind power developments have occurred in offshore areas and in Scotland.

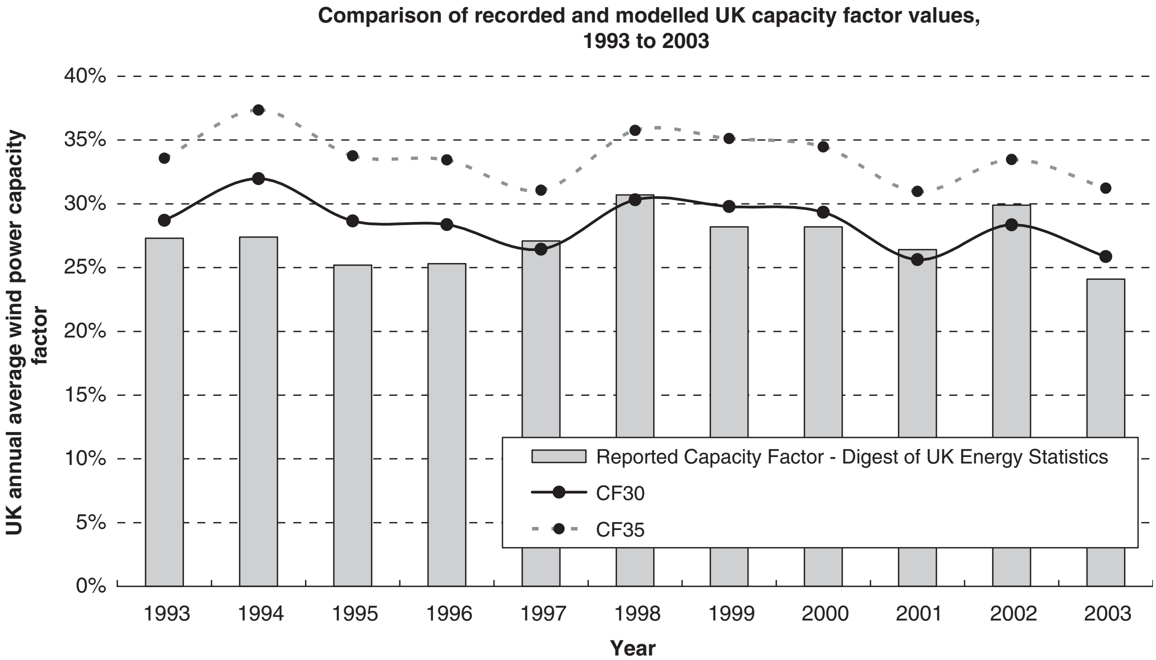

Fig. 1. Comparison of modelled and observed annual capacity factor for UK wind power, 1992–2003.

It must also be recognised that the capacity factor of wind power has a limited role in determining the characteristics of the UK wind resource; a higher capacity factor will reduce the amount of generating capacity required to generate a specified amount of energy from the wind. However, its impact on patterns of availability such as seasonal changes in average wind power availability will be very limited. The relative change in capacity factor at different timescales is far more important than the long-term average capacity factor when addressing issues related to the variability of wind power output patterns.

3.1.1. Inter-annual variability

Wind power availability in the UK varies on an annual basis. Fig. 2 presents the annual capacity factor that would have been achieved in each year from 1970 to 2003 by a diversified wind power system in the UK with a long-term average capacity factor of 30%. Annual capacity factor values range from a minimum of 24.1% to a maximum of 35.7%; the single largest change between years occurred during 1986–1987, where average UK capacity factor fell from 34% in 1986 to just over 24% in 1987. Based on this series, the variability in energy delivered per year was calculated to be 7.4% (standard deviation of year-ahead difference in energy delivered as a percentage of long-term energy production).

3.2. Monthly wind power variability

Fig. 3 shows the average capacity by month for a UK diversified wind power system with a long-term average annual capacity factor for wind of 30%. The winter months of December, January and February account for around one-third of annual electricity production, with CF values between 25% and 33% higher than the long-term average. The three summer months of June, July and August account for just 17% of annual electricity production, with capacity factor values around two-thirds that of the long-term average.

3.3. Diurnal variability

The UK wind resource shows a clear pattern of higher wind power output during daylight hours in comparison to overnight. Fig. 4 presents the long-term average pattern of daily variability on a seasonal basis, with wind power output for each hour being given as the long-term average capacity factor for that season and hour.

The increase in daytime wind capacity factor is most pronounced in summer, with overnight capacity factor figure of around 13%, and a peak daytime capacity factor of 31% (average summer capacity factor of 20%). In comparison, winter output varies from 36% overnight to a peak of 44% during the day, with a winter average capacity factor of 38%. The result for summer also shows capacity factor increasing earlier in the day compared to the other seasons, with elevated capacity factor figures apparent from 7 am until 10 pm, in comparison to the winter pattern of elevated capacity factors from 10 am until 7 pm. This pattern matches the seasonal pattern of solar thermal radiation being experienced during the different seasons and hours, with thermal-induced winds more prevalent in summer than winter.

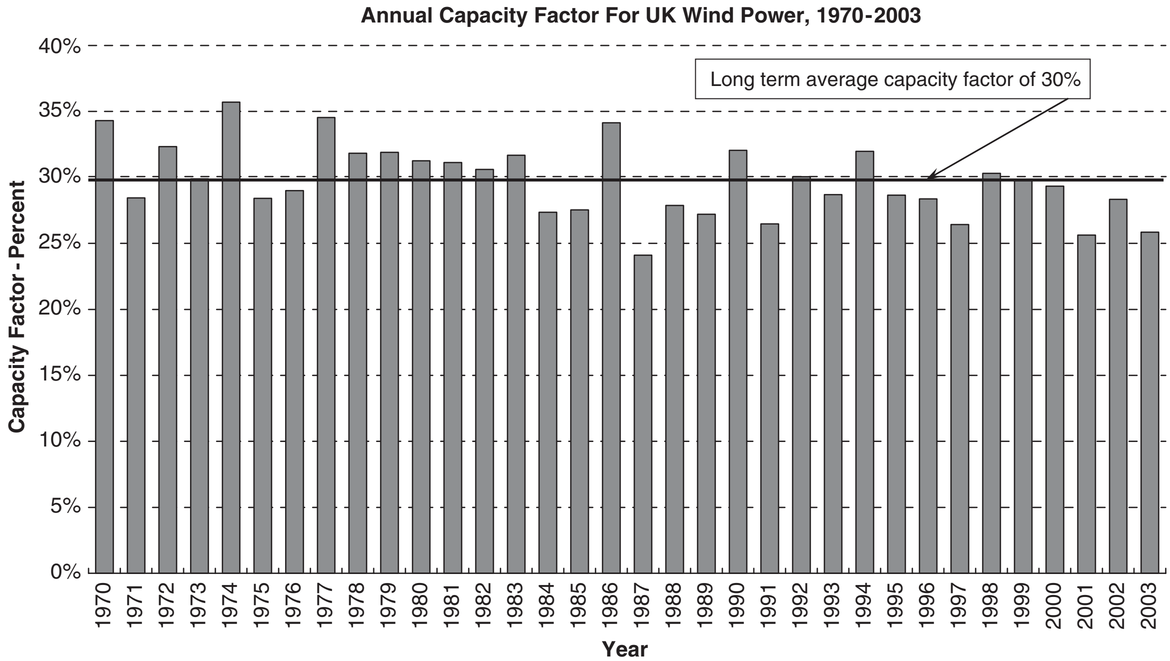

Fig. 2. Annual capacity factor for UK wind power, 1970–2003.

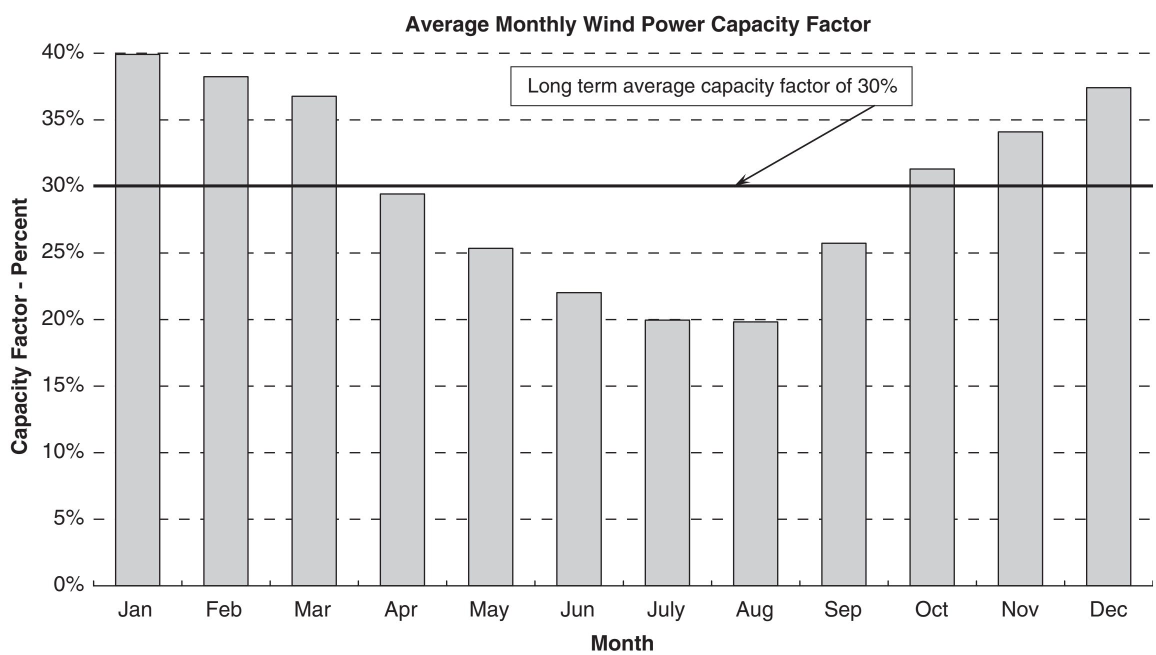

Fig. 3. Monthly wind power availability (averaged over 34 years of wind speed data).

4. The wind resource and geographic diversity

Wind power availability has been shown to have both seasonal and diurnal patterns of availability over the long term; however, these patterns tend to mask other key features of the wind resource. This section explores two such areas—the degree to which output patterns from different wind sites are correlated, and the impact that a diversified wind power system has on smoothing overall wind power output.

4.1. Wind power output correlation and distance

The variability of wind is not a fixed property, as different geographic locations will experience different wind conditions at any given time. This relationship is

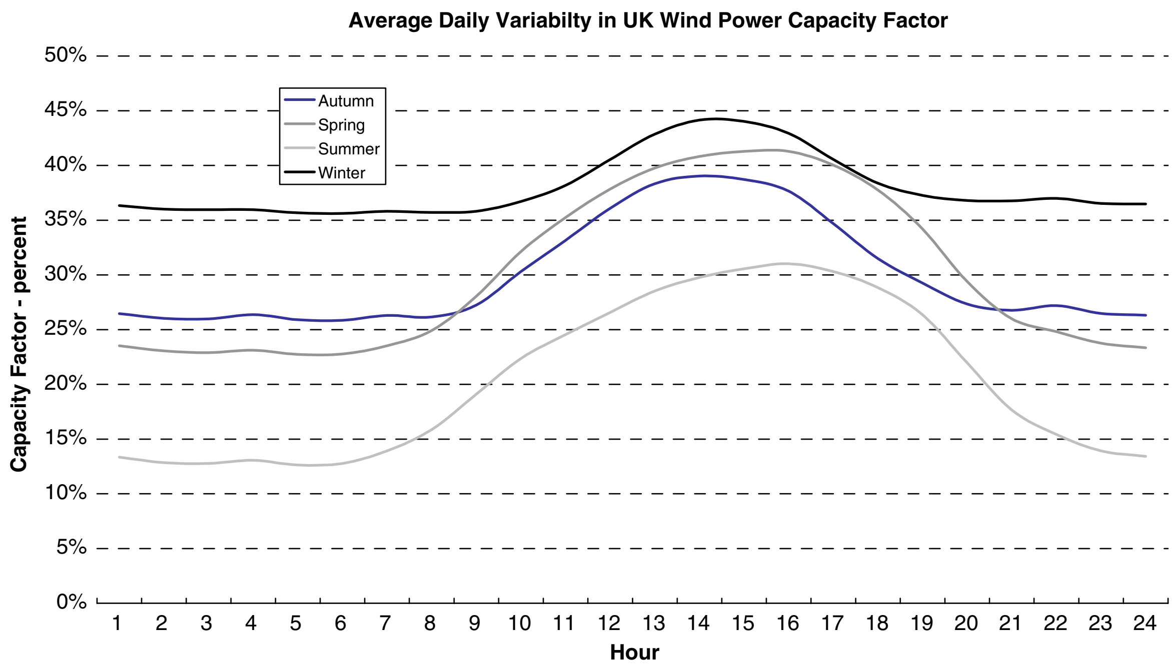

Fig. 4. Average hourly wind power availability by season (averaged over 34 years of wind speed data).

important for reducing the overall variability of the wind power supply; just as the profile of total electricity demand is far smoother than the demand profile of any one household or office, combining the output from different wind power developments acts to smooth the aggregate profile of wind electricity production.

The key to this smoothing effect is that the correlation between wind power patterns at different sites decreases with increasing distance between the sites. No two wind sites will experience identical patterns of wind speed over the long term, and this difference in wind characteristics can be exploited to reduce the overall level of variability from a diversified portfolio of wind-generating sites. The correlations between 2080 pairs of onshore wind sites in the UK as a function of the distance between the sites have been calculated, and these demonstrate that sites far apart exhibit very low correlation (Fig. 5).

This effect is quite pronounced for wind sites within 600 km of each other, with increasing distance being associated with a decrease in similarity between output patterns. For wind sites 800 km or more apart, there appears to be little change in correlation; at these distances, the correlation between the output patterns of different sites is very low, with one pair of sites recording a slightly negative correlation at 900 km (not shown in Fig. 5).

By developing new wind farms with wind patterns that show a low correlation with existing sites, the overall variability of electricity supplied from the wind power portfolio would be reduced. This smoothing effect is limited by the area over which the electricity network extends—once wind capacity has been installed at the most distant locations available on the network, additional capacity will exhibit higher correlation with the existing capacity as there is necessarily less distance between them.

4.2. *Effect of diversification on aggregate output*

By diversifying the development of wind power sites, the variability exhibited by the aggregate output from the UK wind farms would be reduced. One of the impacts of the smoothing that results from exploiting the distance–correlation relationship is that the change in power output from the UK wind farms would be less sensitive to changes in the UK average wind speed than would be expected from the power output curve of a single wind turbine (Fig. 6).

Fig. 6 shows that aggregate turbine output is higher than that predicted by the theoretical power output curve for low average wind speed conditions, while providing a lower average output from a diversified system at higher average wind speeds. This initially surprising result can be understood with reference to a simple example—consider two wind turbines in different locations, with one experiencing winds of $10\,\mathrm{m\,s^{-1}}$, and one experiencing winds of $2\,\mathrm{m\,s^{-1}}$ (giving an average wind speed of $6\,\mathrm{m\,s^{-1}}$). According to the theoretical power output curve, this average wind speed would result in an average power output of 253 kW. However, the high-speed site has a power output of 1333 kW while the low-speed site has a power output of zero, resulting in an average power output of 667 kW, substantially higher than that determined from the average velocity.

Two further features of the UK wind resource are revealed in Fig. 6; firstly, average wind speeds never drop to zero, demonstrating that calm conditions never extend

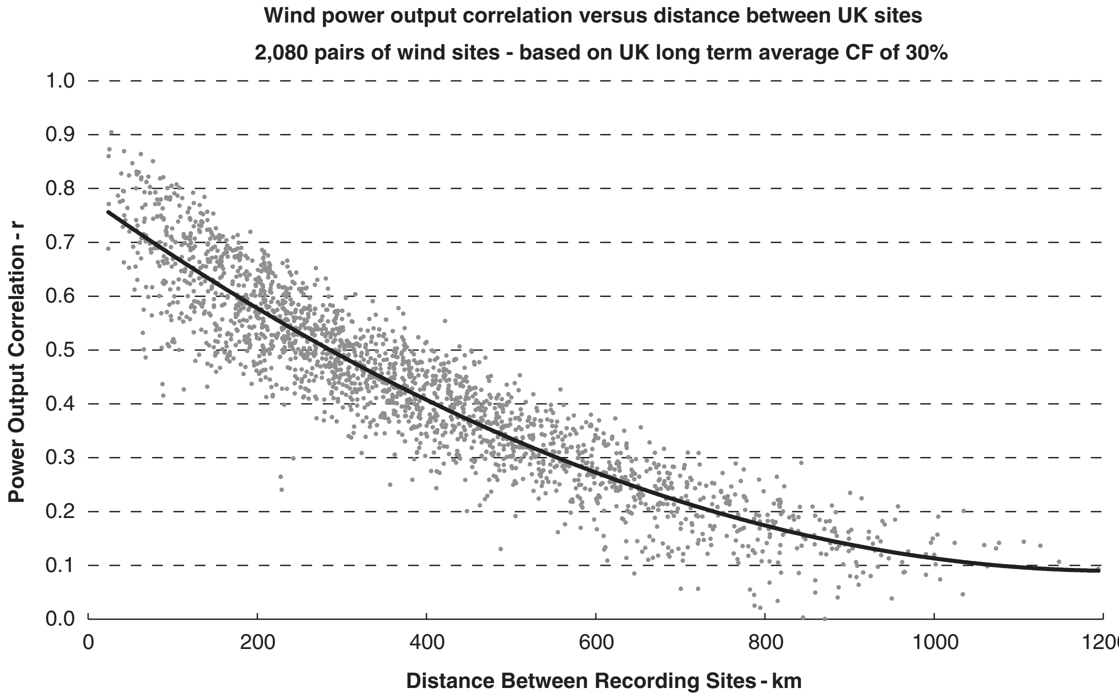

Fig. 5. UK wind speed correlation by distance between recording sites.

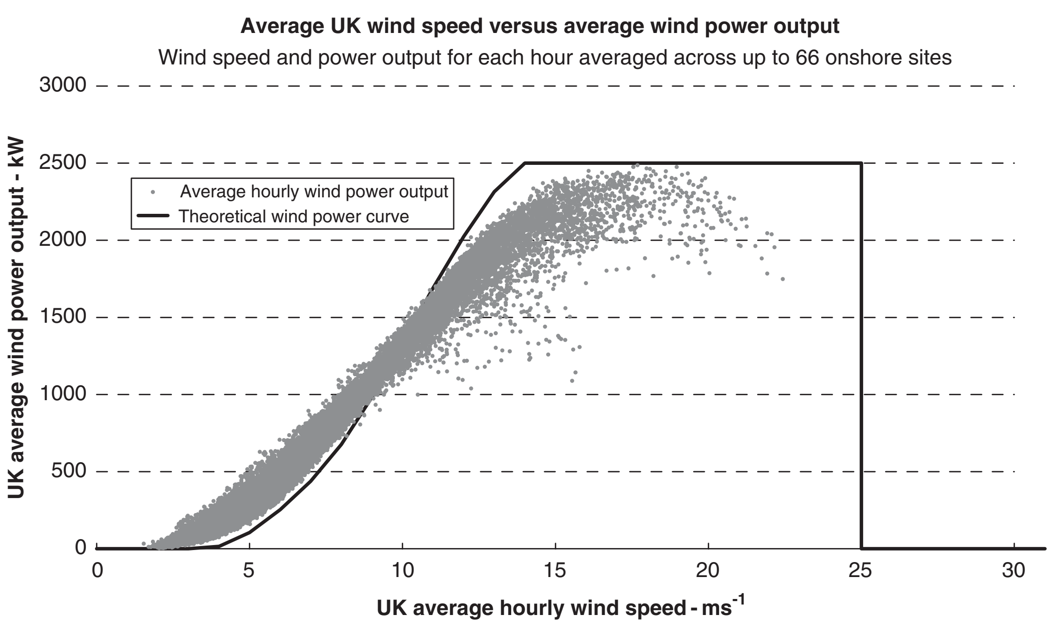

Fig. 6. Smoothing of turbine output curve through geographic diversification.

across the entire UK. Secondly, during hours where the average wind speed exceeds $10\,\mathrm{m\,s^{-1}}$, average turbine output is typically above 50% capacity factor, suggesting that large-scale outage due to high-speed wind events do not affect the entire UK. Both these aspects of the UK wind resource are considered further in the following section.

4.3. Large-scale wind power outage

Despite the effects of geographical diversity, concerns have been raised that occasional large-scale weather systems will cause output to drop across the system; Laughton (2002) has expressed concern regarding UK-wide low-wind events, while Sharman (2005) has suggested that large-scale high-wind events will be a feature of the UK wind resource. Under both scenarios, electricity generation from wind turbines would cease.

Low wind speed events are defined as average hourly wind speed measurements less than $4\,\mathrm{m\,s^{-1}}$ ($14\,\mathrm{km\,h^{-1}}$, 9 mph), which is a common cut-in speed for modern wind turbines—note that this is a significantly higher criterion than that of calm conditions (or $0\,\mathrm{m\,s^{-1}}$). High wind speed events are defined as average hourly wind speeds above $25\,\mathrm{m\,s^{-1}}$ ($90\,\mathrm{km\,h^{-1}}$, 56 mph), which is the wind speed at which many modern turbines commonly shut down as a safety measure. This high wind speed criterion is an approximation of the decision rules regarding turbine shutdown at high wind speeds—these rules often assess gust speed over different (sub-hourly) time periods as part of the decision process for operation. It was not possible to include these decision rules in the assessment of high wind speeds, as sub-hourly data were not available across the UK, and gust data are commonly not recorded.

At individual wind recording sites, periods of no-generation are clearly apparent in the wind record—on average, turbines located at individual wind-recording sites will generate electricity for around 80% of all hours in a year. Low wind speed events are responsible for the vast majority of hours with no generation—approximately 99% of all no-generation hours are the result of low-wind conditions, with high-speed wind conditions accounting for the remaining 1% of hours without generation.

4.3.1. Low wind speed events

The frequency and extent of low wind speed events has been determined for the UK, and is presented in Fig. 7. Over the course of a year, low wind speed events affecting more than half of the UK are present for less than 10% of all hours, while for more than 60% of all hours, less than 20% of the UK is affected by low wind speeds. At the extreme, low wind speed events affecting more than 90% of the UK have an average recurrence rate of 1 h per year. There were no hours in the model dataset where wind speed was below $4\,\mathrm{m\,s^{-1}}$ (the minimum wind speed for electricity generation for many modern wind turbines) throughout the UK.

4.3.2. High wind speed events

High wind speed events are far less common than low wind speed events, with the UK being entirely free of high-speed winds for over 96% of all hours (Fig. 8). The average recurrence rate for high wind speed events affecting more than one-third of the UK is 1 h in 3 years, while the most extreme event identified saw high-speed winds affecting 43% of the UK (observed rate of around 1 h in 30 years). During the period 1970–2003, there was never an occasion when the whole of the UK experienced high wind speeds.

5. Relationship between wind power output and electricity demand

The successful integration of wind power into electricity networks will be assisted by understanding the characteristics of the resource, and how these characteristics relate to key issues regarding the wind power and energy security. Sections 3 and 4 have described the long-term output characteristics of the UK wind resource, including seasonal and diurnal patterns of average wind power output, together with the likelihood of large-scale unavailability of wind power due to low- or high-speed wind events.

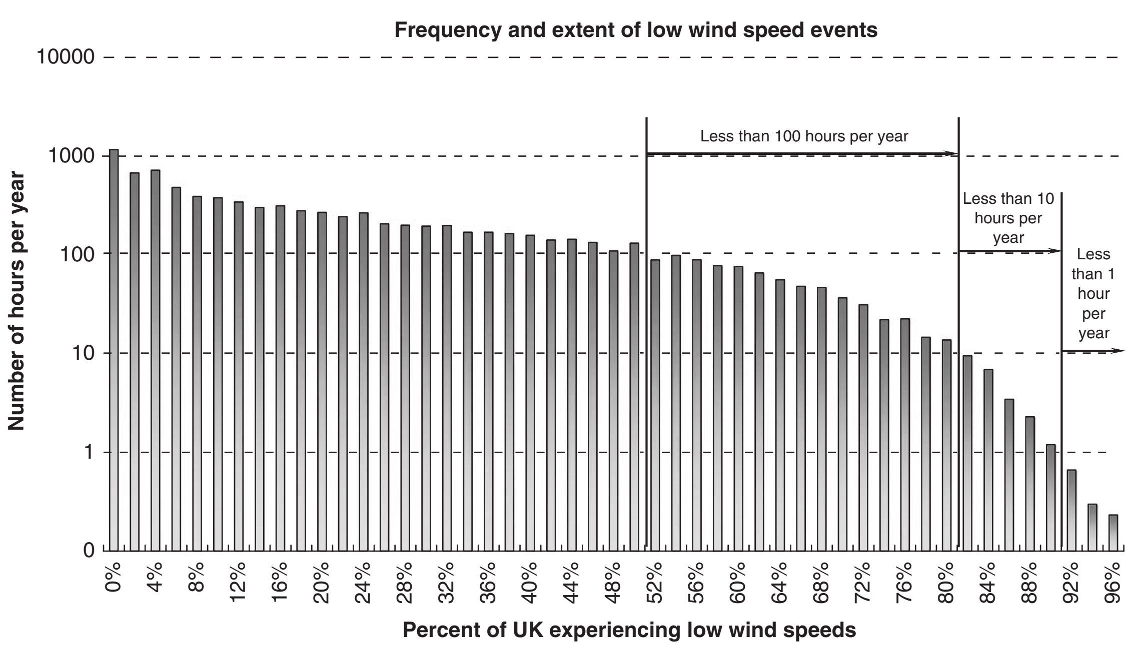

Fig. 7. Frequency and extent of UK land area affected by low-speed wind events.

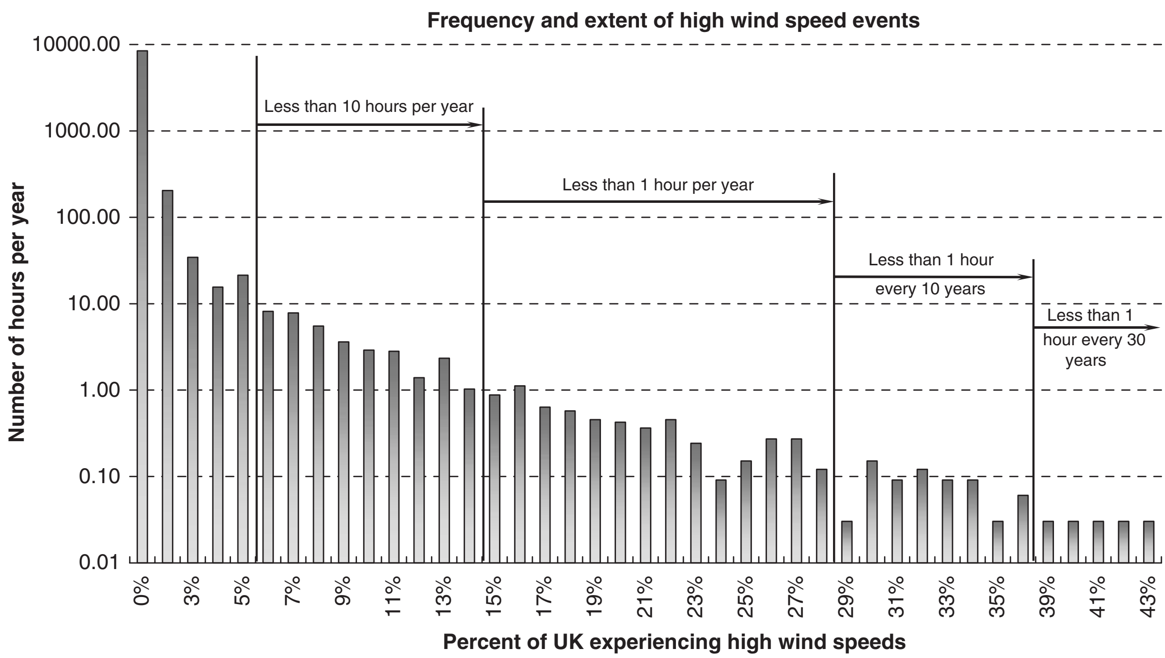

Fig. 8. Frequency and extent of UK land area affected by high-speed wind events.

While this type of analysis provides an excellent insight into the patterns of availability of wind power, it is ultimately the relationship between wind power output and electricity demand that is of greatest interest for the integration of wind power into electricity networks.

In the UK, there is a broad match between patterns of electricity demand and patterns of wind power availability—electricity demand is higher in winter and during the day and early evening, a pattern that broadly coincides with the seasonal and diurnal availability of wind power. It has also been suggested that the wind chill produced by high winds causes a rise in electricity demand above the average demand level expected for the time of year (Dale et al., 2003), while the occurrence of low wind speed events during winter peak undermine the value of wind power during these times.

This section examines the pattern of wind-generated electricity in relation to hourly electricity demand. Concepts including the relationship between wind-generated electricity and demand, and the differences between wind power output distributions during different electricity demand periods, are examined. Finally, the ability of wind to form part of a diversified electricity-generating network is discussed in light of the data presented.

5.1. Data and presentation

5.1.1. Data sources

The results presented in this section rely on an analysis of matched hourly wind speed and electricity demand data. Hourly electricity demand data were obtained for England and Wales for the period 1996–2004; this period overlaps with the available UK wind speed data for around 8 years (1996–2003), and it is data from this overlapping period that forms the basis of the results in this section. England and Wales account for around 88% of total UK electricity demand (DUKES, 2004)—while the inclusion of demand data from Scotland and Northern Ireland would provide a more robust estimate of total demand, it is considered unlikely that the exclusion of this electricity demand will significantly affect the pattern of hourly electricity demand used for these analyses.

By analysing a subset of the total wind speed data, there is an increased chance that the results will be influenced by shorter-term changes in wind power characteristics. For example, while the full wind power dataset achieves a long-term average capacity factor of 30%, the subset of years included in this section has an average capacity factor of 28%; this must be recognised when interpreting some of the results.

5.1.2. Presentation method

Electricity demand data are presented by percentile rank, meaning that each hour in each year is assigned a ranking from 1 (hour of maximum demand) to 8760 (8784 for leap years) for the hour of minimum demand. These ranked hours were then grouped into one-percentile bands, and time-matched wind power data were associated with each percentile band.

This approach has been adopted as it ensures that a relatively even number of hours are included in each percentile band. An alternative approach was considered in which hourly electricity demand was presented as a percentage of the peak hourly demand in each year, in a manner similar to that used by Oxera (2003). However, this approach can see the number of hours in each percentile

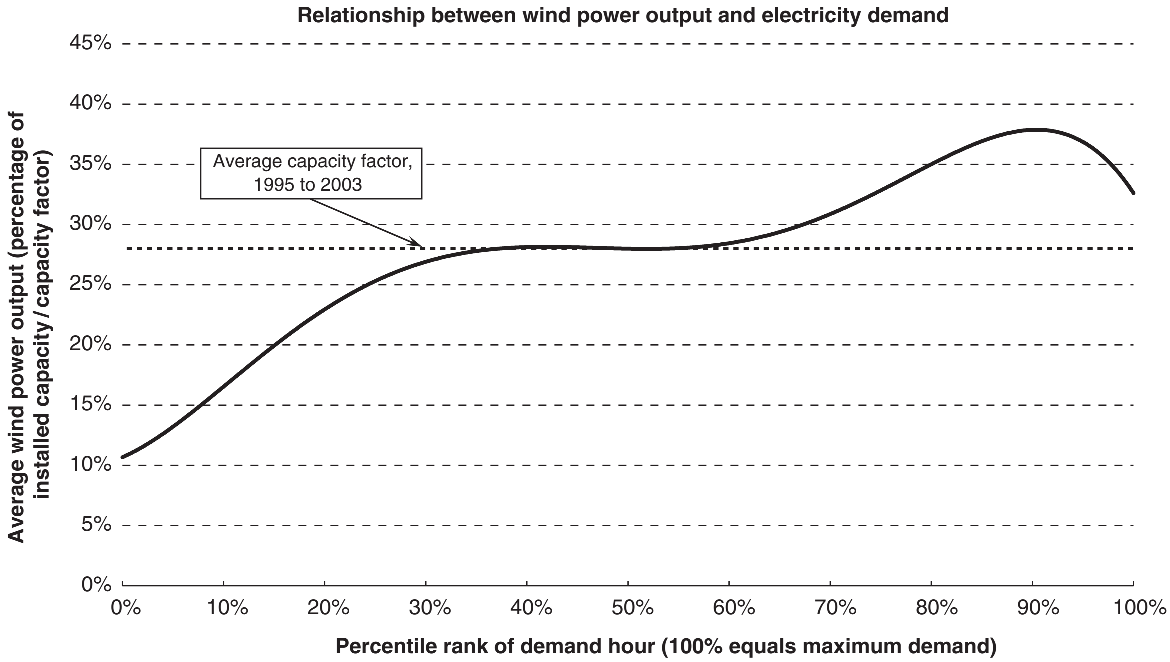

Fig. 9. Relationship between wind power availability and electricity demand.

band varying by a factor of 20 or more, and can result in misleading interpretation of the data.

5.2. Wind power output and electricity demand

The capacity factor of wind power is often presented as an annual average figure; this method of presenting the performance of wind power neither takes into account the seasonal and diurnal patterns of wind power availability nor recognises the seasonal and diurnal patterns of electricity demand in the UK. By determining the average availability of wind power during different electricity demand hours, and presenting this availability as a function of demand, the relationship between average wind power output (capacity factor) and electricity demand can be seen (Fig. 9).

A relationship of wind power output increasing as electricity demand rises is clearly shown in Fig. 9. During periods of high electricity demand (80–100 percentile), the capacity factor of wind power averages around 37%; this represents an average wind capacity factor around one-third higher than the long-term average capacity factor of 28%. There is a modest decline in wind power capacity factor in the 90–100 percentile band; while this suggests that wind power has a slightly lower average output at this time, the capacity factor during peak electricity demand hours remains above the long-term average.

During low electricity demand periods, the availability of wind power is markedly reduced, with the lowest 10% of demand hours associated with an average wind power capacity figure of 13%, or less than half the long-term average capacity factor. Overall, the capacity factor for wind power during the highest demand hours is almost 3 times higher than that occurring during the lowest demand hours.

These results do not imply that all demand hours will experience the average capacity factor figures presented in Fig. 9—there remains considerable variability in the hourly capacity factor occurring during these times, as is demonstrated by the low correlation coefficient between hourly electricity demand and wind power output of 28% (Pearson's *r*). However, this result does suggest that the distribution of hourly wind power output levels will change for different levels of electricity demand—this aspect of the data is explored in detail in Section 5.4.

5.3. Wind–electricity relationships at times of extreme wind conditions

While the occurrence of low-speed wind events is limited and high-speed wind events extremely rare (Section 4.3), they represent an important characteristic of the UK wind resource. However, it is not just the presence of low- or high-speed wind events that is important to quantify—the critical aspect in terms of the reliability of the UK wind resource in contributing to electricity demand is the availability of wind power at different times of the year and electricity demand levels. For example, if low or high wind speed events were to routinely occur during times of high electricity demand (often between 5–7 pm in winter in the UK), then the value of wind in meeting peak electricity demand would be undermined.

This sensitivity of wind characteristics to time of year is also apparent for low wind speed events; e.g., the extreme event of 75% or more of the UK experiencing low winds affects around 0.8% of all hours: However, during winter, this falls to

0.2% of hours. This is not an unexpected result given the seasonal patterns in wind power availability that have been identified; however, it does highlight the importance of assessing both the timing and magnitude of wind events.

While the influence of seasonal patterns of wind power availability is clear, it will ultimately be the hour to hour relationship between wind power availability and electricity demand that is key to understanding the potential of the UK wind resource—this relationship is considered in the following section.

5.3.1. Low-speed wind events and electricity demand

Over the long term, low wind speed events are less likely during periods of high electricity demand than during periods of low electricity demand (Fig. 10). On average, around 82% of the UK experiences winds strong enough to generate electricity during the highest 10% of electricity demand hours—by comparison, during the lowest 10% of electricity demand hours, the average area of the UK experiencing winds strong enough to generate electricity drops to around 63%.

The maximum extent of low wind events in the UK follows a pattern similar to that of the average extent of low wind conditions, with the area of the UK affected decreasing slightly as electricity demand rises. It must be emphasised that the "maximum extent" data shown in Fig. 10 relates to extremely rare events—these data represent the single most extensive low-speed wind event occurring in around 8 years at the different demand levels.

It has been claimed that during each winter, the UK experiences periods when there is no wind throughout the country, and that this is due to the presence of high-pressure systems (Fells, 2003). While there is slight increase in both average and maximum areas affected by low wind speed conditions during hours of high electricity demand (possibly due to large-scale weather systems), the impact of these events is modest. Indeed, data on the average and maximum extent of low wind conditions presented in Fig. 10 demonstrate that during the highest 10% of electricity demand hours, the extent of low wind speed events is below the long-term average.

5.3.2. High-speed wind events and electricity demand

High-speed wind events are extremely rare in the UK; on average, they affect a very small proportion of the UK, with the most extreme events remaining relatively limited in extent. However, there is a complex relationship between the extent of the event and electricity demand (Fig. 11).

On average, less than 0.1% of the UK experiences high wind speed conditions at any one time, with the impact being at its least during very low electricity demand hours. During periods of high electricity demand (85–95 percentile demand bands), the impact is at its greatest; however, high-speed wind events affect on average less than 0.2% of the UK at these times. Note that in the highest 5% of demand hours (95–100 percentile bands), the impact of high-speed wind events declines to around the long-term average.

The maximum extent of the UK experiencing high-speed wind events is also shown against demand in Fig. 11. High wind speed events exhibit their greatest extent during periods of relatively low electricity demand; extreme events affecting over 30% of the UK always coincided with the

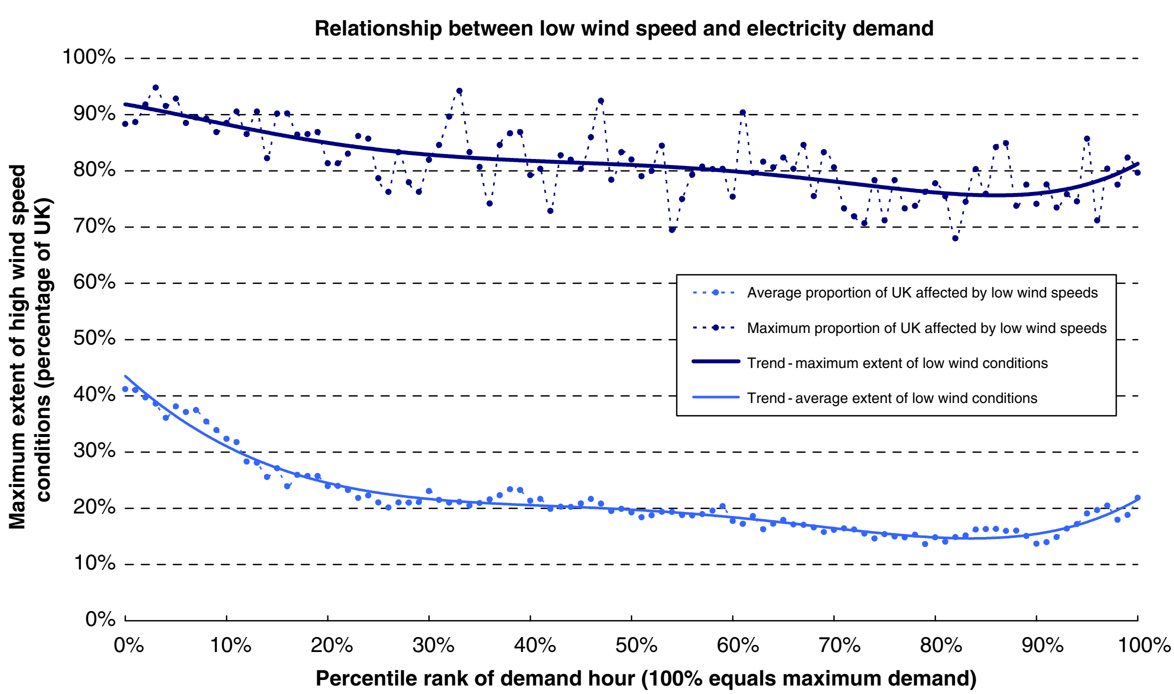

Fig. 10. Relationship between low wind speed events and electricity demand.

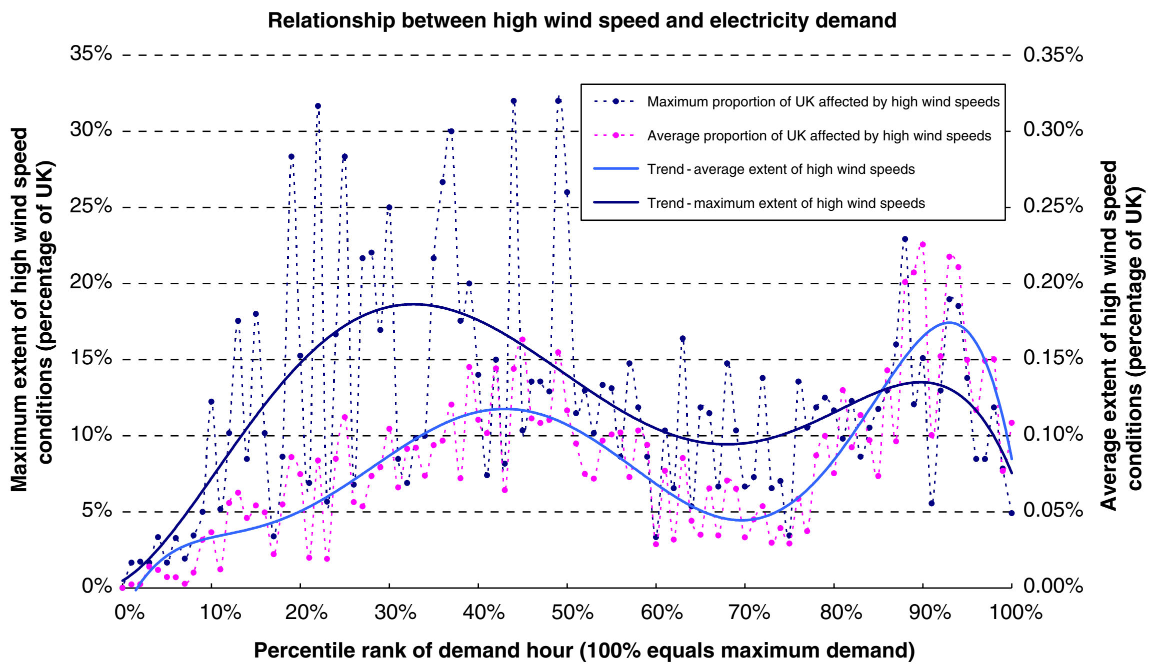

Fig. 11. Relationship between high wind speed events and electricity demand.

lower half of ranked electricity demand hours, while the maximum extent of high wind events during peak electricity demand hours was typically less than 10% of the UK. Again, these high-speed wind events are extremely rare, with the data shown in Fig. 11 representing the maximum extent of high wind speeds from 8 years of hourly data.

5.4. *The distribution of wind power during high and low electricity demand*

The findings of the previous section suggest that there is a fundamental difference in the characteristics of the wind resource during different times of the year, and hence, at different levels of electricity demand. This difference is particularly apparent in Fig. 8, which demonstrated that large differences in the average capacity factor of the UK wind resource are associated with changes in hourly electricity demand.

Based on these results, the hourly wind power output dataset has been partitioned into two subsets:

- Peak demand hours—the hourly wind power output records associated with an hourly electricity demand rank in the 80–100 percentile range.
- Low demand hours—the hourly wind power output records associated with an hourly electricity demand rank in the 0–20 percentile range.

These data have been grouped into probability distributions showing the likelihood of different wind power output levels associated with both peak and non-peak demand hours (Figs. 12 and 13); the annual average distribution of wind power is shown in each figure for reference.

There is a clear difference between the wind power output distributions associated with peak electricity demand periods and low electricity demand periods, reflecting the seasonal differences in the characteristics of wind power in the UK. Wind power output levels during high electricity demand periods (80–100 percentile demand hours) are relatively evenly distributed in comparison to the annual average distribution, with a bias remaining towards the lower end of the output range (Fig. 12). There is an increased probability of high wind power output, and a corresponding decrease in the probability of low wind power output, during periods of high electricity demand; this translates into a capacity factor during peak electricity demand hours that is around one-third higher than the annual average.

During low electricity demand periods (0–20 percentile demand hours), there is a pronounced bias towards lower wind power output levels, with wind power output equal to less than 10% of installed capacity in almost half of all low demand hours (Fig. 13). Wind power output during hours of low electricity demand is less than half that of the long-term annual average output.

Figs. 12 and 13 demonstrate the importance of accurately matching wind characteristics with electricity demand levels. By adopting the annual average wind distribution as the basis for examining wind output patterns during high electricity demand hours, periods of low wind output would be overestimated, periods of moderate to high wind power output would be underestimated, and the overall contribution to meeting energy demands during peak demand hours would be

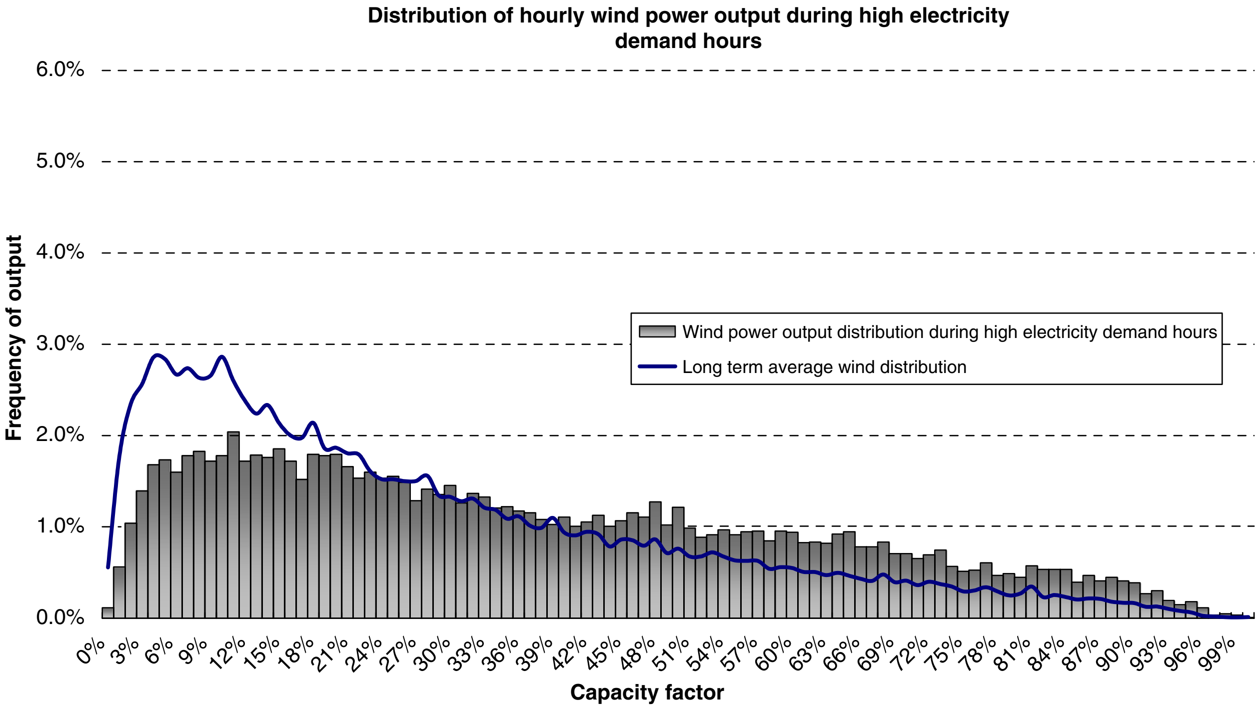

Fig. 12. Distribution of hourly wind power output during peak electricity demand.

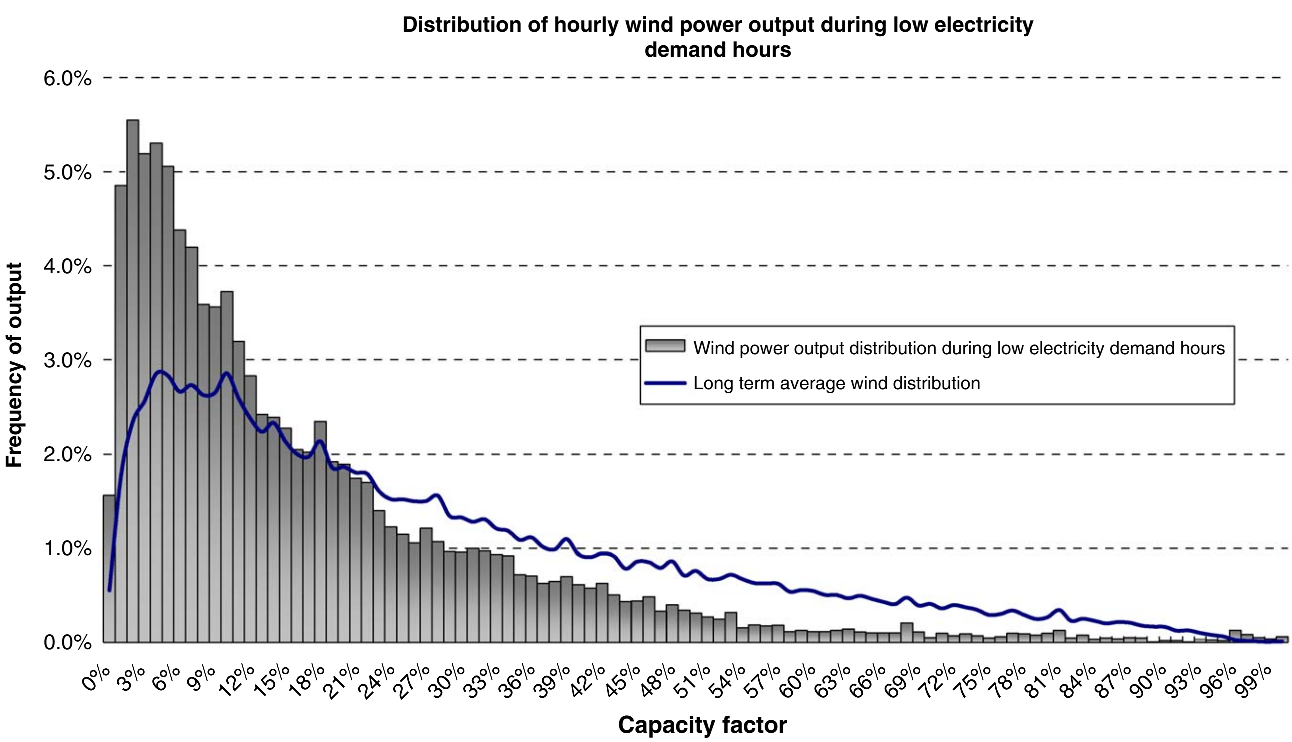

Fig. 13. Distribution of hourly wind power output during non-peak electricity demand.

underestimated. Relating wind characteristics to electricity demand levels will ensure a more accurate view of the contribution wind power can make to meet electricity demand.

5.5. Contribution of wind power to electricity demand

The combined variability of wind power output and electricity demand in the UK will result in the contribution

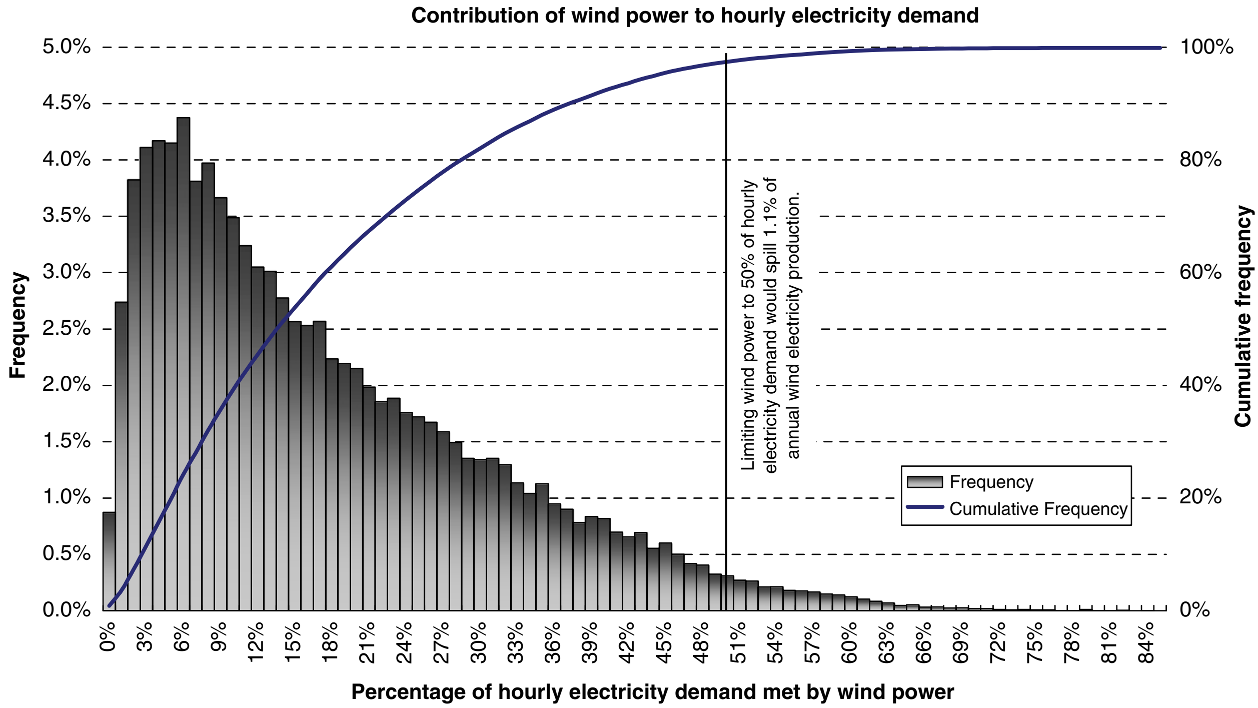

Fig. 14. Contribution of wind power to hourly electricity demand.

of wind power to electricity demand varying from hour to hour; under a scenario of high wind power penetration, it is theoretically possible for wind power output to exceed demand during some hours. One such scenario is presented below, with wind power supply around 20% of total electricity demand:

peak system demand: 60 GW,
minimum system demand: 22 GW,
installed wind capacity: 25 GW (30% capacity factor).

Under such a system, it is theoretically possible for the output of wind power alone to exceed demand in some hours. The analyses presented in Section 5.4 demonstrate that the probability of very high output during low electricity demand hours is rare. However it is necessary to compare wind output to demand on an hourly basis to determine the impact of these low probability events.

The relationship between hourly observed electricity demand and modelled wind power output demonstrates that the worst case scenario of wind power output exceeding electricity demand would not have occurred in the 8 years of data available for this research, with the highest wind power contribution level observed equal to 84% of demand (Fig. 14). This figure shows that there is a strong bias towards low relative contributions of wind power to electricity demand—in over half of all hours, the contribution of wind power is 14% or less of hourly demand.

One strategy that could be employed to reduce the proportion of wind power meeting demand in any given hour would be to establish a cap on wind power output. For example, wind power output in this scenario would exceed 50% of electricity demand in around 2.5% of all hours (220 h each year); by limiting the contribution of wind power to a maximum of 50% of electricity demand (by reducing the output of wind turbines), around 1% of the total annual energy produced by wind power would be spilt. Such a strategy would represent a trade-off between lost earnings for wind electricity generating companies, and potentially lower network costs arising from fewer hours of high wind electricity contribution.

6. Wind power in electricity networks

Wind power developments in the UK do not operate as stand-alone systems, but are integrated into existing electricity generation and supply systems. When seen as a whole, these systems reliably deliver electricity from a range of generating technologies; however, none of the individual components of the system are wholly reliable. Conventional generators such as gas, coal and nuclear exhibit varying degrees of intermittency in their electricity output, while resources such as wind power present a variable electricity supply to the network.

It has been argued that wind power cannot be relied on to supply any capacity to the electricity network, as there is a small (but non-zero) probability of low wind power output coinciding with high electricity demand (Laughton, 2002; Royal Academy of Engineering, 2003). However, this argument is inconsistent with the experience gained from existing electricity networks. Conventional generators have periods of zero output, and there is a small (but non-zero) probability of these periods coinciding with high electricity demand. Yet experience demonstrates conclusively that existing electricity systems, comprised of intermittent conventional electricity generators, do reliably meet electricity demand. Furthermore, a large number of authors have concluded that the need for conventional capacity will be reduced by the presence of wind power in an electricity system (cf. Dale et al., 2003; Grubb, 1991; Grubb and Meyer, 1993; Milborrow, 2001, 2003), demonstrating that wind power can be relied on to provide capacity for the network.

Probabilistic assessments of security of supply, such as loss of load probability (e.g., see Billinton, 1970) and other reliability indices, provide a widely recognised method for quantifying the reliability of electricity networks in meeting demand; they also offer a robust method of examining the impact that wind power capacity would have on an electricity network. Probabilistic assessments view the electricity generating system as a collection of generators with statistically varying output, which operate together to meet demand with a known level of reliability. An intrinsic aspect of these methods is their ability to quantify the impact that periods of non-generation have on the ability of the system to meet electricity demand, by determining the probability of non-generation occurring across a number of individual generators resulting in an electricity supply below the demand level.

Within a probabilistic assessment, wind power can be treated simply as an electricity generator that has different statistical properties of availability than conventional generators. Quantifying these statistical properties requires an understanding of the key characteristics of the wind resource; e.g., Fig. 11 describes the distribution of wind power availability at times of peak electricity demand, and it is this distribution that is most important in determining the impact of wind power on system reliability. By linking the temporal availability of wind power with electricity demand patterns, an improved understanding of how the characteristics of the UK wind resource affect wind power integration into electricity networks will be achieved.

7. Conclusion

This paper has identified long-term trends in the average seasonal and diurnal availability of the UK wind; the UK experiences a seasonal maximum in wind power availability during winter, and an increase in wind power availability during the day compared to overnight. The occurrence of extreme low and high wind speed events in the UK wind record were also examined, including periods during which wind power output would be curtailed. It was found that low wind speed events have a limited impact on the UK, and that high wind speed events are extremely rare; no hours were identified where electricity production from wind power throughout the UK was curtailed due to these extreme events.

The relationship between wind power output and electricity demand levels was examined, and a trend of increasing energy production from wind power during high electricity demand periods was identified. From this observation, the distribution of wind power during high- and low-demand periods was identified, demonstrating both the variability of the wind resource and the difference in wind availability between these two periods. Finally, the integration of wind power into electricity networks was discussed in relation to these empirical findings, and emphasised the need to accurately incorporate wind power characteristics associated with different demand levels into wind power and electricity system modelling.

Acknowledgements

This research was supported by the University of Oxford through the Clarendon Fund Bursaries, and the University of Cambridge Department of Economics through the Supergen Future Network Technologies consortium. The assistance of the British Atmospheric Data Centre and the National Grid Company in supplying data used in this research is gratefully acknowledged. Finally, my thanks to Dr Brenda Boardman and Professor Michael Grubb in reviewing early drafts of this paper, and to Dr Karsten Neuhoff for comments on the analyses.

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