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Evaluating the accuracy of CFSR reanalysis hourly wind speed forecasts for the UK, using in situ measurements and geographical information

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ABSTRACT

Climate data can be used in simulations to estimate the output of wind turbines in locations where meteorological observations are not available. We perform the most comprehensive evaluation of the NCEP CFSR reanalysis model hourly wind speed hindcasts to date, and the first for the UK, by correlating the data against 264 onshore and 12 offshore synoptic weather stations, over a period of 30 years. The correlation of CFSR data to in situ measurements is similar to alternative approaches used in other studies both onshore and offshore. We investigate the impact of the topography, land use and mean wind speed on the onshore locations for the first time. The analysis of these spatial factors shows that CFSR represents the variety of terrain over UK well, and that the worst correlated sites are those at the highest elevations.

1. Introduction

Medium-term European Union (EU) energy policy requires 20% of primary energy to be supplied by renewables and a 20% reduction in greenhouse gas emissions from 1990 levels by 2020 (an agreement colloquially known as EU 202020). The renewable target is not evenly split between member states; the UK's target is to supply 15% of energy demand from renewable resources by 2020, which represents a substantial increase on the 4% actual contribution of renewables in 2012 [1]. Currently, renewable electricity is the largest contributor to these targets; capacity grew by 38% to 19.5 GW between July 2012 and June 2013. Wind capacity increased onshore by 1.6 GW–7 GW and offshore by 41%–3.5 GW in the same period [2]. Fig. 1 illustrates the growth of wind capacity, onshore and offshore and summarises a number of medium term forecasts on wind capacity. The spread of values, steadily increasing in magnitude, demonstrates that beyond the next several years there is a great deal of uncertainty about the extent to which wind will contribute to the UK energy mix. The onshore forecasts appear low compared to the previous installed capacity, because some of the forecasts were made before this capacity was installed, which further illustrates the difficulty of predicting future capacity. According to these scenarios, the largest predicted combined capacity by 2020 may be more than 50 GW and the smallest less than 20 GW.

One of the key challenges when introducing large wind capacities is to cope with varying intermittent generation. As wind speeds vary across the UK and are different onshore and offshore, the level of intermittency for the electricity system depends on the location of wind farms. Wind speed is influenced by factors that change over small spatial resolutions such as terrain, elevation and buildings, as well as air density and other weather influences [7]. These changes can result in local measured differences of up to an order of magnitude [8]. The same factors influence changes in wind speed over all temporal resolutions from seconds (e.g. gusts due to building driven wind tunnels) to decades (e.g. changes in weather and climate), driving intermittent generation. The varied terrain in the UK means that there is considerable spatial diversity in this intermittency.

Historically, wind capacity in the UK has been small, particularly when compared to feasible future scenarios (Fig. 1). Data from operational wind farms in the UK is only available over a short time period, which may not include low frequency climate events such as extended periods of high or low wind. It is also unlikely that the wind speeds experienced by existing capacity are as diverse as those that will be experienced by future wind farm fleets, particularly with the addition of offshore capacity. Consequently, it is

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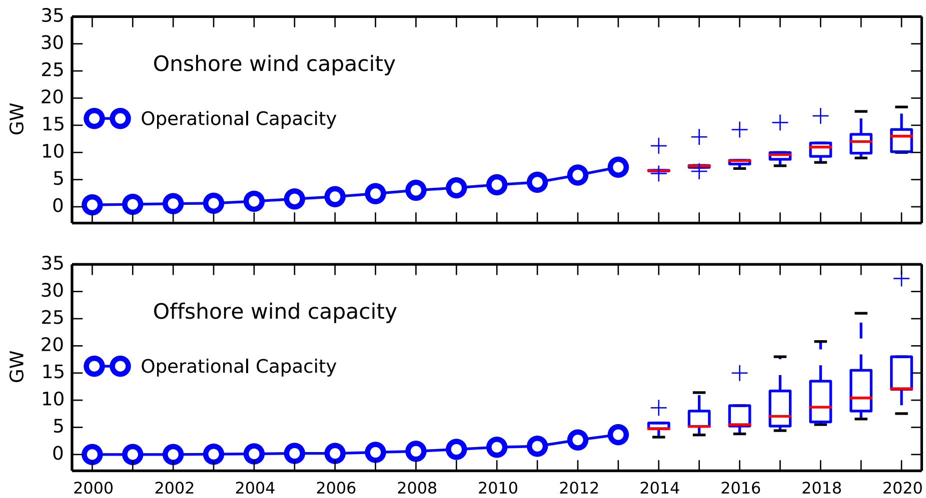

Fig. 1. Installed and projected wind capacity, derived from data on installed capacity from DECC [3] and forecasts from DECC. [4], National Grid [5], Renewables Advisory Board and Douglas Westwood [6]. The boxplots represent the forecasts, the central line is the median; and the edges of the box are the 75th and 25th percentile. The whiskers are the most extreme points, the gap between the dash and the whiskers is due to the fixed length of the dash, the pluses are outliers.

difficult to extrapolate current generation trends to future deployments, especially as there is little data available on generation at a disaggregated level. An alternative approach is to estimate generation using wind speed data from either weather station observations or from weather or climate models, for both regional planning and at the scale of an individual wind farm or turbine.

1.1. Estimating potential wind generation through simulation

1.1.1. Onshore, using weather station data

Some studies estimate the spatiotemporal variation of wind generation across large onshore areas by interpolating historical measurements from synoptic weather stations. Weather stations measure wind speed at a height of 10 m and several statistical methods have been developed to estimate wind speed at the turbine height, which is typically assumed to be 80 m [see Ref. [9]]. Electricity generation from a turbine can then be estimated from these data using a power curve provided by turbine manufacturers (e.g. Fig. 2). In the UK, this method has been used to investigate the impacts of intermittency [10–12], and to explore scenarios of national output [13,14] using synoptic MIDAS[1] data [15]. MIDAS wind speed observations are provided as hourly mean values at the most temporally disaggregated level. This represents a compromise compared to using measured turbine output; these mean values have been shown to vary between ± 30 to 40% when compared to minutely values, meaning that some of the intermittency is smoothed [8].

The UK network of synoptic weather stations is spatially diverse and, onshore, appears to be spatially comprehensive (Fig. 3). Attempts to assess the wind resource across the UK, [e.g [10]], have assumed that the wind harnessed by farms would be represented by a subset of these stations; however, station networks are generally biased towards populated areas, where wind farms cannot be built, and towards low lying areas that experience lower wind speeds [16]. Moreover, the land uses at many weather stations are unsuitable for the location of turbines, for example urban areas or wetlands. It is also possible that the locations which *are* suitable for wind farm development are not used for other reasons, such as planning restrictions or low wind speeds. There is no existing research that explores the impact of synoptic station location with respect to either wind turbine simulation or evaluation of other wind datasets.

Alongside these spatial issues, MIDAS, in common with all weather observation datasets, has gaps and duplications. Data are also provided at multiple temporal resolutions, with repeated time steps and apparently erroneous values. These discrepancies must be filtered in order to obtain a continuous dataset.

1.1.2. Onshore, using reanalysis data

Some researchers have looked for alternative data sources to overcome these disadvantages. One option is climate reanalysis, which provides a global time series for a range of climate variables on a gridded basis at a number of different altitudes. All of the latest generation of climate reanalyses utilise a core of conventional data, including wind speed, temperature, moisture and air pressure, as well as other data such as precipitation. Data sources change owing to new technologies being introduced; current platforms include, but are not limited to, radiosonde, satellite, buoy, aircraft and ship reports [17]. Data are run through a global circulation model (GCM)

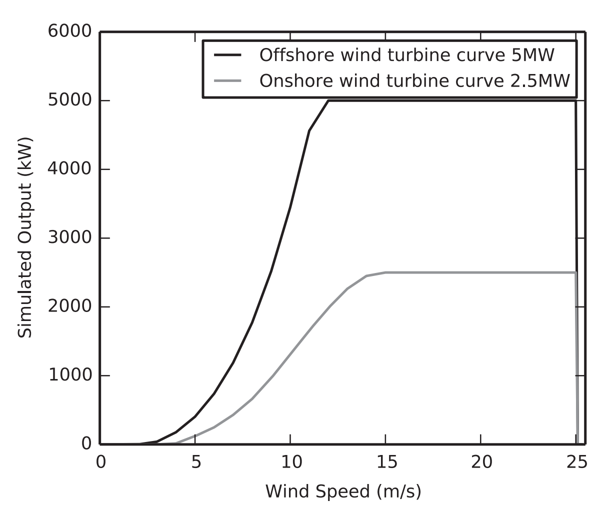

Fig. 2. Wind turbine curves used for simulation; above 25 m/s there is no generation as turbines are designed to cut-out to avoid damage from excessive vibration.

[1] MIDAS is the UK Met Office Integrated Data Archive System.