Space and Time Analysis of Irradiation variation across the UK: A 10 Year Study of Solar Farm Yield

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Abstract

This research offers an understanding of year-to-year and area-to-area variability of PV performance, measured in terms of specific yield (kWh/KWp). This information will assist in grid management.

Introduction

The last few years have seen the quantity of grid-connected PV systems increase and become more distributed, both in the UK and worldwide. Potentially, there could be overloads on the UK National Grid. Situations may arise where there is excess of power produced at times when it is not utilised or in places where demand is relatively low. For example in Germany, the grid capacity is not sufficient for transporting the extra power provided by renewable energy sources which resulted in a number of curtailments [1]. Also, in Australia, it has been found that power outrages are more likely in rural areas because the network may be weaker and there is land available for large PV installations [2]. The UK is now beginning to experience similar problems. One of the essential 132kV power lines in the South West has reached its full capacity. That is, connected and committed capacity equal the maximum rating of the circuit. Therefore a delay of 3 – 6 years has been imposed on all new generation requiring infrastructure at 11 kV or above [3].

Despite these recognised problems, little is known about when and where on the electricity grid PV generation is likely to deliver its maximum generation. Nor is there any information on whether full rated capacity is actually attained. The stage of impact on grid hierarchy (national or local grid) is also unknown. Given the changeability of the UK’s weather patterns, it surmised these factors will prove complex.

This paper sets out to fill these gaps in knowledge. It aims to demonstrate the spatial and temporal variability of PV generation in the UK. Two levels of analysis will be employed. Firstly, PV generation will be studied by aggregation to Distribution Network Operator (DNO) area because these organisations are responsible for operational security. Also few local network power lines cross DNO boundaries. Secondly, each PV installation will be allocated to its nearest grid supply point. Grid supply points are used in the national demand forecast. Supply points with the highest input will be identified and accessibility of PV systems to the grid will be determined.

The influence of PV generation on each area of the grid is demonstrated by calculating combined output based on solar farm installation data released by the Department of Climate Change Renewable Energy Planning database, REPD 2015 (575 x 1-50MW installations at September 2015). This contains details of the location and capacity of solar farms. It is assumed that all these PV systems are south-facing with an elevation of 22 degrees and comprise crystalline silicon module types (standard values). DC energy output is calculated in all cases.

Calculation of PV Output Data

The REPD 2015 does not contain PV output data, so it was computed from national hourly irradiance and temperature datasets [4] in a series of stages as follows. Firstly, global horizontal irradiation and ambient temperature data from UK Met. Office ground meteorological stations were interpolated to produce a countrywide grid of values. The kriging interpolation technique was chosen (see [5]). Ten years’ data (2005-2014) was used. There are 80 or more weather stations which routinely record irradiation, spread unevenly across the UK. Temperature data is more widely measured, with almost 500 weather stations. Having filled the gaps between weather stations, the value at the point nearest each solar farm was selected.

Next, the global horizontal irradiance values obtained are translated to in-plane irradiance. Separation into beam and diffuse components takes place [6]. Each component is then transposed to the inclined plane [7-8].

Module temperature is calculated from the in-plane irradiance and ambient temperature using a thermal model. Finally, having obtained all necessary input, an electrical model is employed to compute output power. Both the applied thermal and electrical models are described in [9].

Aggregation of Data

DNO areas were manufactured from Lower Superoutput Area boundaries downloaded from Office of National Statistics website. A lookup table from Elexon was used to dissolve internal boundaries and create the larger DNO regions.

Initially, data at DNO level was produced by simply taking the average irradiance of all solar farms falling within the area and the total output. However, it soon became obvious that this was furnishing “wrong” results. For instance, Yorkshire appeared to have the highest annual global horizontal irradiation of all the DNOs. This phenomenon of statistical analysis varying when individual points are collected into geographical areas sometimes occurs. It is called the Modifiable Area Unit Problem (MAUP) [10]. The results obtained depend on the size and shape of areas used. Solutions in the literature include re-zoning or merely using individual data points. These techniques are not appropriate in this context, so the problem was approached in the following manner:

1. Global horizontal irradiance and ambient temperature values were produced by averaging all interpolated values falling inside the DNO area. (As opposed to previously, when values nearest to the solar farm locations were selected)
2. The latitude of the DNO centroid was used to calculate beam/diffuse separation and plane-of-array irradiance. Output was estimated as before and scaled-up by total capacity of solar farms in the area.

This solution was arrived at because the beam/diffuse split model is latitude specific. Although it appears counter-intuitive to use only one location per area, the results are more realistic. The single centre point is more representative of the whole area than solar farms which could cluster e.g. away from cities, or along a main road.

Grid supply points serving the transmission system were obtained from [11]. Supply point areas were constructed by Delaunay triangulation. That is, each supply point was joined to its two nearest neighbours by a straight line. The perpendicular bisector of each joining line is drawn. When each bisector meets another bisector, they are connected to form a set of polygons (Figure 2).

Results and Discussion

Basic statistical analysis has been performed on the data to investigate the variability of PV generation in the UK at several time resolutions. The spatial variations are also considered.

To begin with annual global horizontal irradiation per DNO was mapped in order to investigate whether any statistical bias due to aggregation still remained. Results are much as expected, with highest irradiation appearing in the south of the UK (Figure 1).

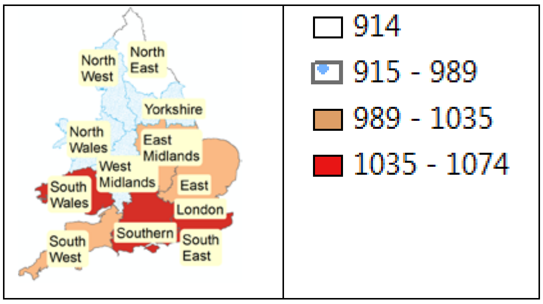


Figure 1: Average Annual Global Horizontal Irradiation of each DNO, kWh/m^2. (Ten-year average 2005-2014)

Location of solar farms is obviously influenced by availability of the solar resource. Figure 2 illustrates the number of solar farms per grid supply point (GSP) area. The massively unequal number of PV installations feeding into the Indian Queens substation in Cornwall is self-evident. However, in terms of input capacity, this substation is topped by Minety in Wiltshire, Mannington in Dorset and Burwell near Cambridge. There is also the issue of practical distance to the grid. Solar farms situated over 45km to a supply point were discovered on the North Pembroke coast, Norwich and again in Cornwall. These may stress the local distribution network.

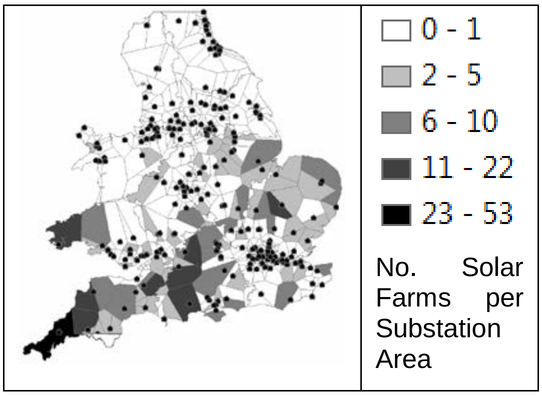


Figure 2: Location of Grid Supply Points (black dots) and division into Supply Areas

Another form of grid limitation is the imbalance of supply and demand. Figure 3 indicates that these are incompatible with solar farm supply being generated in rural areas and demand occurring predominantly in large cities e.g. London, Manchester.

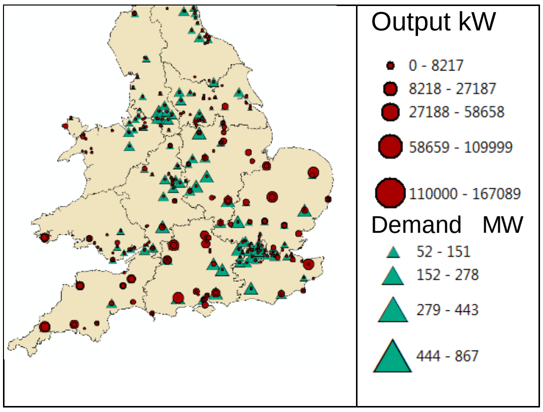


Figure 3: Calculated Solar Farm Output 2014 allocated to GSP compared to Electricity Ten Year Statement GSP Winter Peak Demands 2015

More sophisticated analyses subsequently commenced. Average kWh/kWp over ten years was analysed countrywide (Figure 4). Again the results are fairly predictable, with very low generation occurring for the vast majority of daylight hours. Individual DNOs show very similar patterns.

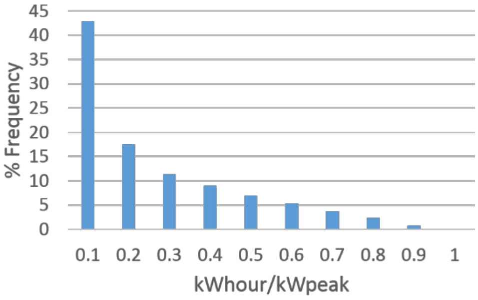


Figure 4: Percentage of daylight hours in each kWhour/kWpeak bin (2005-2014)

Hourly trends were analysed for the UK as a whole and for individual DNOs. (Figure 4 shows a sample for simplicity.) The UK average value is highest at 1pm. Those DNOs in the east of the country peak at noon, whilst westerly located DNOs maximise at 1pm. The Southern England area, which is central, also peaks at around 1pm. Eastern DNOs have highest output in the morning and western ones in the afternoon. The DNO with the greatest kWh/kWp is South Wales. The lowest is the East Midlands. (See Fig. 5.) These tendencies are much as anticipated.

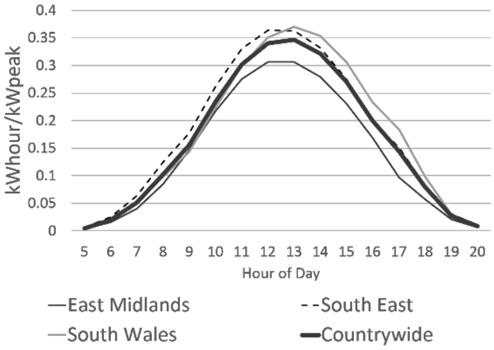


Figure 5: Average kWh/kWp per hour (2005-2014)

Variation of individual DNOs from the national average is demonstrated in Figure 6. The hours with the widest spread between areas are also the most productive hours i.e. the middle of day. Difference in values may be explained by DNO latitude and longitude and the associated changing position of the sun.

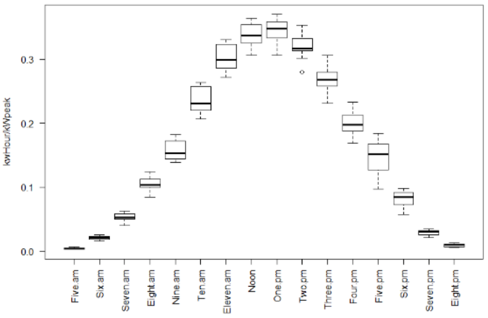
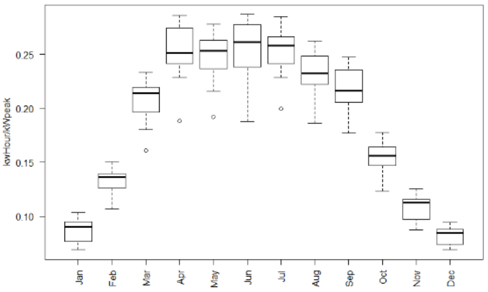


Figure 6: Boxplots illustrating Variability of average hourly kWhour/kWpeak (5am – 8pm) for each DNO (2005-2014)



When average hourly values are compared between years, a similar picture emerges. The average value e.g. of 10am 2005 was compared to average 10am figure for every year to 2014 and the standard deviation calculated. The most variable hour for the whole country was found to be 2pm. The hours with the largest standard deviation for single DNOs range from 11am to 3pm. No link between geographic position and time is discernable. The only noticeable feature is that all these times are in the middle of the day. This may be because cloud cover is more general mornings and evenings, decreasing the variability of output as well as reducing it. The air warms during the day and therefore holds more moisture. This triggers unpredictable cloud dispersal, influenced by topography and local weather systems. In the evening the air cools and clouds form again.

Moving to daily grouping of data reveals some interesting patterns (Figure 7). Daily higher and lower values than the prevailing tendency occur every 5-15 days. Figures are generally better than the overall trend from March to September and again during December when high pressure dominates the weather. Lower than expected values occur in blocks at the end of February (when the wind direction may veer north), late May (again the wind may be northerly) and from the end of September to the beginning December (autumn storms).

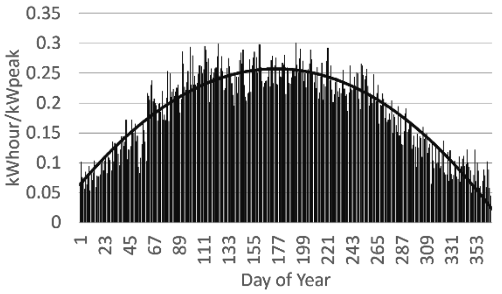


Figure 7: Average kWh/kWp per day (2005-2014)

Monthly figures rise to June and then fall away (Figure 7.) June is also has the greatest spread between DNOs.

Figure 7: Boxplots illustrating Variability of average monthly kWh/kWp for each DNO (2005-2014)

However, April has higher than expected values and is also the month with the greatest inter-annual variability. One possible explanation is that irradiance values begin to increase in the Spring whilst temperatures can still be low. This combination enhances PV output.

Conclusion and Future Work

This research has resolved data aggregation obstacles to deliver some surprising findings. The stresses on the network may not arise solely in Cornwall. April solar farm output may equal that of June. The most productive hour of the day is also one of the most variable. Perceived grid stresses were investigated from four viewpoints: DNO/GSP area with highest number of solar farms, DNO/GSP area with highest solar farm capacity, greatest distance of solar farm to nearest GSP, and imbalance of supply and demand. Since full capacity is seldom achieved, it is distance over local networks to GSP and imbalance which are likely to have the greatest impact on the national grid. In addition, output varies, according to geographic position (east / west), hour of day and time of year. There is a need for further investigation, particularly to compare output, capacity and demand.

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