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Large scale integration of wind power – influence of geographical allocation

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Abstract.

This paper investigates the influence of geographical allocation of wind power generation in Northern Europe, assuming large scale integration of wind power. The work applies a linear cost optimization model of the heat and power sector with a 1-hour time resolution. The model minimizes the sum of running costs to meet the heat and power demand and the wind power and transmission investment costs. Wind data are taken from modelled wind speed data from the Swedish Meteorological and Hydrological Institute. The Nordic countries and Germany were divided into regions and the 200 sites with the highest yearly output were chosen to represent the region. The model gives the most favourable distribution of wind power between the regions. In addition, the paper provides an assessment of the effect of geographical distribution of wind power with respect to influence on the aggregated wind power production (only considering the wind power generation itself).

The modelling results show that the largest investments in wind power are made in the windy region of Southern Norway. However, depending on the cost of transmission allocating wind power near large load centers in Germany may also be favourable. As for the assessment of distribution of wind power, the wind data gives that if the 400 best sites in Europe were used, this would result in a capacity factor of 38.5% and a lowest output of 2.5 % of rated power (applying 2009 wind data).

Key words

Wind power, Large-scale integration, Geographic allocation

1. Introduction

Wind power is considered a key technology to decrease carbon dioxide emissions from the electricity generation sector. Thus, large investments in wind power are expected in the European electricity generation systems in order to comply with the EU renewables (RES) directive (by year 2020 there should be a 20% share of energy from renewable sources for the EU). Also globally, wind power is expected to make a substantial contribution to greenhouse gas reductions [1]. Yet, wind power is an intermittent (variable) source of energy and such large scale integration of wind power is not straight forward with respect how to find an efficient integration in the existing electricity generation system (generation, distribution and consumption). However, several studies point out that as the share of wind power increases, the capacity credit decreases (see [2] and references therein). The capacity credit is the contribution of wind power to system security. A lower capacity credit means that each kWh of electricity produced from wind will be more expensive. Thus, if the capacity credit can be made higher for a certain share of wind power, it entails a system cost reduction.

Important aspects to consider when integrating a large amount of wind power in the electricity system are:

- Geographical allocation of wind power sites.
- The amount of storage capacity.
- Investments in transmission capacity.
- Possibilities for demand-side management.
- Flexibility in the dispatch of the other power plants in the system, including other renewable generation.

To keep system costs at a minimum, while at the same time introducing a share portion of intermittent wind power, a combined effort of these factors need to be considered. [3].

The balance between investments in wind power capacity and transmission capacity has been investigated by Giebel et al. [4] who conclude that there are economic incentives to allocate the wind investments at sites with good wind conditions, even in cases where this results in investments in long transmission lines. This is confirmed by Göransson and Johnsson [5] who found that a cost minimizing allocation of wind power capacity would imply a concentration of new wind farms to windy regions. Yet, Göransson and Johnsson also conclude that the difference in wind power generation costs between different regions with good wind conditions is in the same range as the difference in transmission costs between these regions and they found that the distribution of wind farms between such windy regions depends on three factors: 1) To what extent existing lines can be used to transmit new wind power, 2) availability of alternative low cost generation and, 3) the correlation in wind power generation between exporting regions. Both [4] and [5] indicate the importance of understanding how wind production varies with wind conditions between different regions. However, Kiss and Jánosi [6] suggest that the distribution of wind power over large areas in Europe will not substantially help decrease the variability in the aggregated wind power output. They found the minimum level of production of 1.1% (of rated power) for the theoretical case of wind power being equally distributed over the entire European continent.

The correlation coefficient between different sites in the Nordic countries has been investigated by Holttinen [7]. The correlation is weak (below 0.5) for distances over 200 – 500 km. However, the fitness of the correlation coefficient as a measure of the potential of smoothing out tops and downs in the wind system output, may be questioned based on the findings of Kiss and Janosí [6].

Considering limitations in the wind speed data in the previous work of the authors [5] and the questioning that distributing wind power over large areas will not substantially help decrease the variability of power output [6], it is important to further investigate the influence of geographical allocation of wind power, especially applying wind speed data with as high a resolution as possible. Thus, the aim of this work is to apply wind speed data with a higher resolution as input to the model given in [5]. The wind speed data is assessed with respect to wind production and a favorable allocation of wind power has been used as input to the modeling. Since there seems to be different conclusions in literature on the possibilities for reducing variability of wind power by means of distributing wind power over large areas, this is also investigated by means of detailed wind speed data.

2. Method

The model is presented in section A, and the wind data used in the modelling in section B. Section C describes the method and assumptions made for the separate investigation on the effect of allocation of wind sites with respect to their theoretical output (not considering any limitations in transmission capacity or interaction with the electricity generation system).

A. The model

The input for the model developed in [5] is an extension of the Balmorel power systems model [8]. The model minimizes the sum of running costs to meet the heat and power demand and the wind power and transmission investment costs necessary to reach an arbitrarily chosen wind power production level. In this work as well as in [3], the level is chosen so as 20% of total generation should be from wind power. The model consists of a stylized transmission network, connecting the regions in Figure 1 wind power output data time series per region, capacity factor per region, estimate of investment cost for wind power per region and estimate of transmission investments per region. Each country is subdivided into regions delimited by bottlenecks in the transmission system, as illustrated in Figure 1.

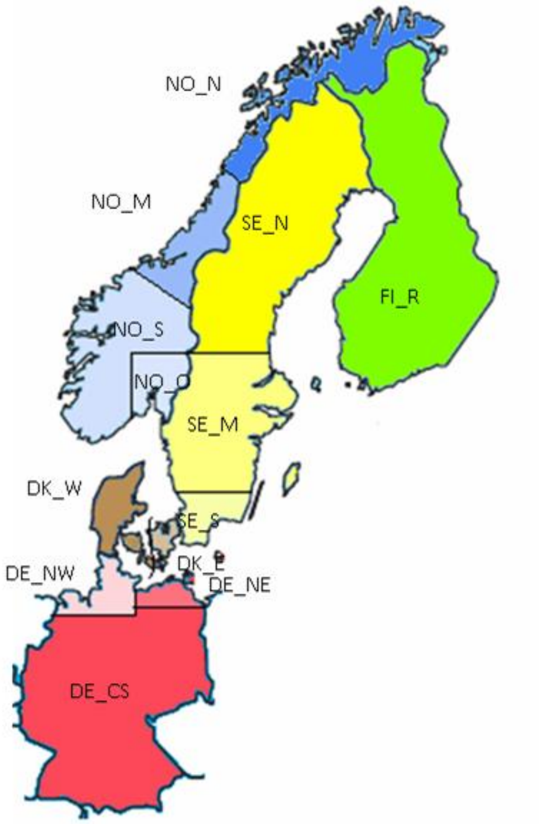

Fig. 1. The regional division applied in the model.

Within each region the electricity demand has to be satisfied each hour, either through electricity generation in units within the region or through import from other regions. The model includes power generation as well combined heat and power generation and heat only boilers. Each region encompasses one or several areas within which the heat demand has to be satisfied. Units generating power and/or heat are allocated to a specific area and aggregated based on technology and fuel. Each wind power investment area includes a description of the possible wind power generation each hour for that specific region and category per MW wind invested. Wind speed data are used as input, recalculated to wind power production data. The wind speed data corresponds to the aggregated output of the 200 sites with the highest capacity factor in each region as obtained from an assessment of the wind speed data (see next section). Curtailment of wind is allowed in the model, but curtailed wind will obviously not contribute to the 20% wind target.

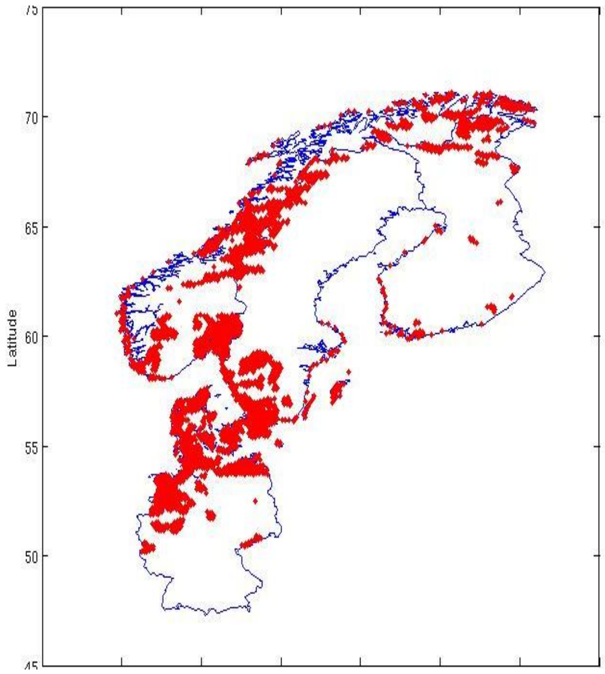

Fig. 2. The red-colored sites used to provide wind power production as input to the model. Wind data from SMHI. The 200 sites with the largest output were chosen for each region (see Figure 1 for regions). The sites are used as an estimate for the regions' capacity factor.

B Wind power production data

The wind data was obtained from the Swedish Meteorological and Hydrological Institute (SMHI) and produced by a meteorological weather model called HIRLAM. The model is updated with observations, i.e. measurements from satellites or weather stations, and produces data for several meteorological quantities, amongst them wind speed at different heights. The spatial resolution (11 km) is fine, compared to other data sets for comparable areas and time spans, i.e. ERA-40 [9]. The temporal resolution is one time point every three hours. The area covered by the data set is shown in Figure 3. The height for wind speed data is taken as 93 m, which was the model level closest to the common height of modern wind power plants. In this work, the grid points corresponding to land area in Sweden, Norway, Finland, Germany and Denmark are used.

The wind data was transformed to output from wind power using a function adapted from [6]. The function is an interpolation of data from statistics of production data from several wind power plants. Yet, the function does not take into consideration shadowing effects from plants and outage due to malfunctioning or maintenance. Therefore, it is reasonable to assume that it is an overestimate, compared to existing plant output. For a further investigation of the discrepancy between model and real output of wind power plants, see [10].

In the previous work with the model [5] two different sets of wind power full load hours were used in the model: One set based on wind speed data from the NCEP/NCAR data base and adapted according to the method developed in the Trade Wind project [11] and one set based on output from existing wind farms [10]. Hourly profiles of wind power generation was derived from NCEP/NCAR data according to the Trade Wind method [12], [13].

C Assessment of aggregated wind power production

As indicated above, this work also includes an assessment of the aggregation of wind speed data with respect to distribution of wind sites (i.e. only the net aggregated wind power output, not considering the interaction with the rest of the electricity generation system). Sites were combined in order to find an aggregation that yielded 1) a high capacity factor (full load hours) and 2) a high minimum output (which is related to the amount of wind power which can be guaranteed and which can be compared with the value of 1.1% as obtained in [4], although an exact comparison cannot be made). As a first step, all sites with a capacity factor of less than 25 % (2,190 full load hours) were removed from the data set. 400 of these sites were combined and the time series of the combinations were analyzed in terms of fulfilling 1) and 2).

The number 400 is chosen using the following assumptions: The plant size is assumed to be 2 MW (approximate size of a new land-based wind power plant). All grid points of installation are assumed to be able to comprise a wind park of a maximum of 100 plants, i.e. a maximum installation of 200 MW/grid point .An arbitrarily chosen level of 20 % wind power is applied. The final electricity consumption in the region was 882 TWh in 2008 [15]. An estimate thus yields that approximately 400 wind park sites are required. This number is, however, approximate at best, and may be further discussed.

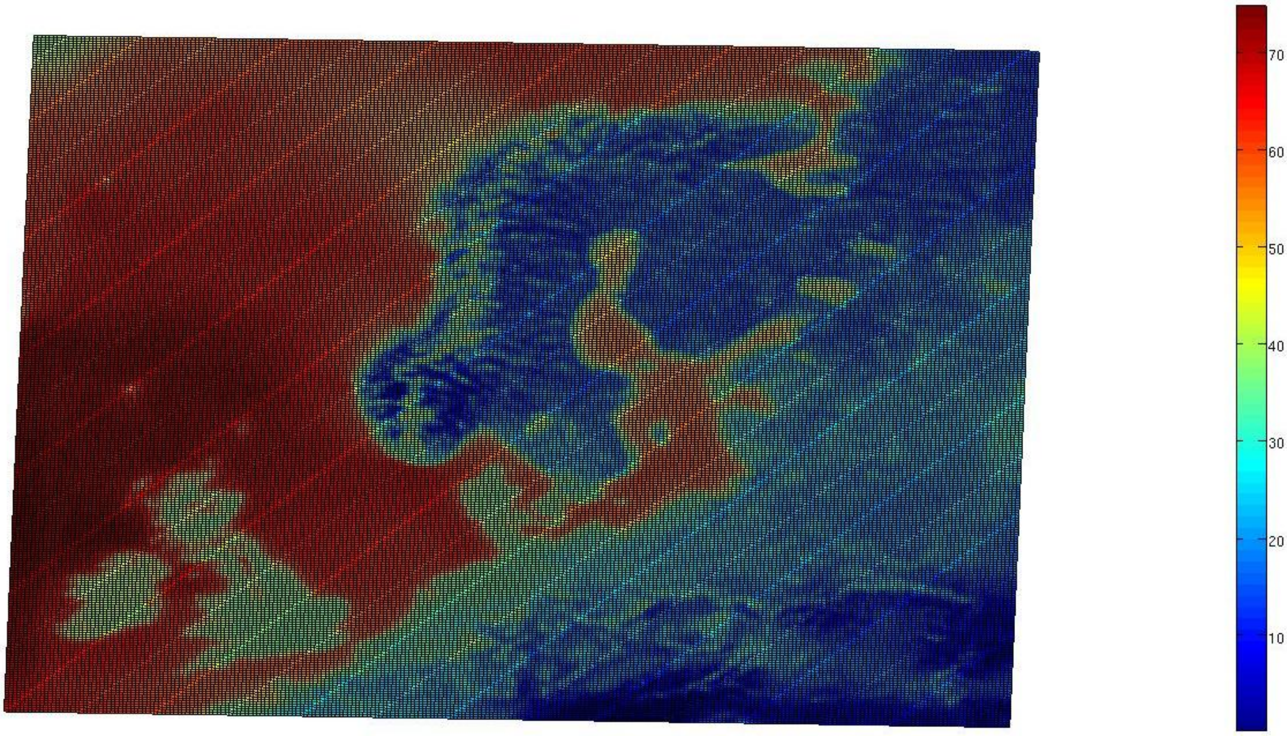

Fig. 3. The spatial data set used here. The grid points are 11 km apart. The colors show the average power output in 2009 of a wind power plant in the grid point.

3. Results

A. *Model results*

Table 2 and Table 3 summarize the results of the model run with the new data from the 200 best sites in each region[1]. The new data input from wind is found in Table 4. Table 1 lists an example of the costs for transmission that are used as model input.

The investment in wind power is dominated by Southern Norway (NO_S); a windy region with transmission to Denmark. This result was also dominant in the previous work [5] with coarser wind data. The results differ from those in [5] in that wind power is also allocated to south-central Germany. The investments in transmission are concentrated to Germany and Denmark, as can be seen from Table 2.

Table 1 Example of transmission investment costs distributed over electricity transferred [EUR/MWh]. Transmission line lifetime: 20 years. Interest rate: 10%. The loads on the lines are reduced by respective losses over the lines. See Figure 1 for specification of regions.

Load on lines	100%	75%	50%	25%
SE_M-DE_CS	15	19	29	58
NO_S-DE_CS	16	21	32	64
DK_W-DE_CS	8	11	16	32
DE_NW-DE_CS	4	6	9	18

[1] Two regions had less than 200 sites, due to that their areas were not large enough: NO_O, represented by 98 points, and DK_E, represented by 76 points.

Table 1 Wind power investments (MW) per region in Figure 1 as generated by the model. For regions not listed, there are no investments.

DK_E	1,477
DK_W	2,653
DE_CS	7,858
NO_S	15,617
SE_N	5,883

Table 2 Investments in transmission capacity (MW) generated by the model. The transmission is symmetric, i.e. the same amount is added in both directions. The numbers shows investment in one direction.

DK_W – DE_CS	1,293
DK_W – DE_NW	499
DE_NW – DE_CS	1,499

Table 4 Regional full load hours input to the model

Region	Full load hours
SE_N	2,775
SE_M	2,514
SE_S	2,263
NO_N	3,315
NO_M	2,893
NO_S	3,359
NO_O	1,351
DK_E	3,054
DK_W	3,176
DE_NE	2,592
DE_NW	2,869
DE_CS	2,607
FI	2,092

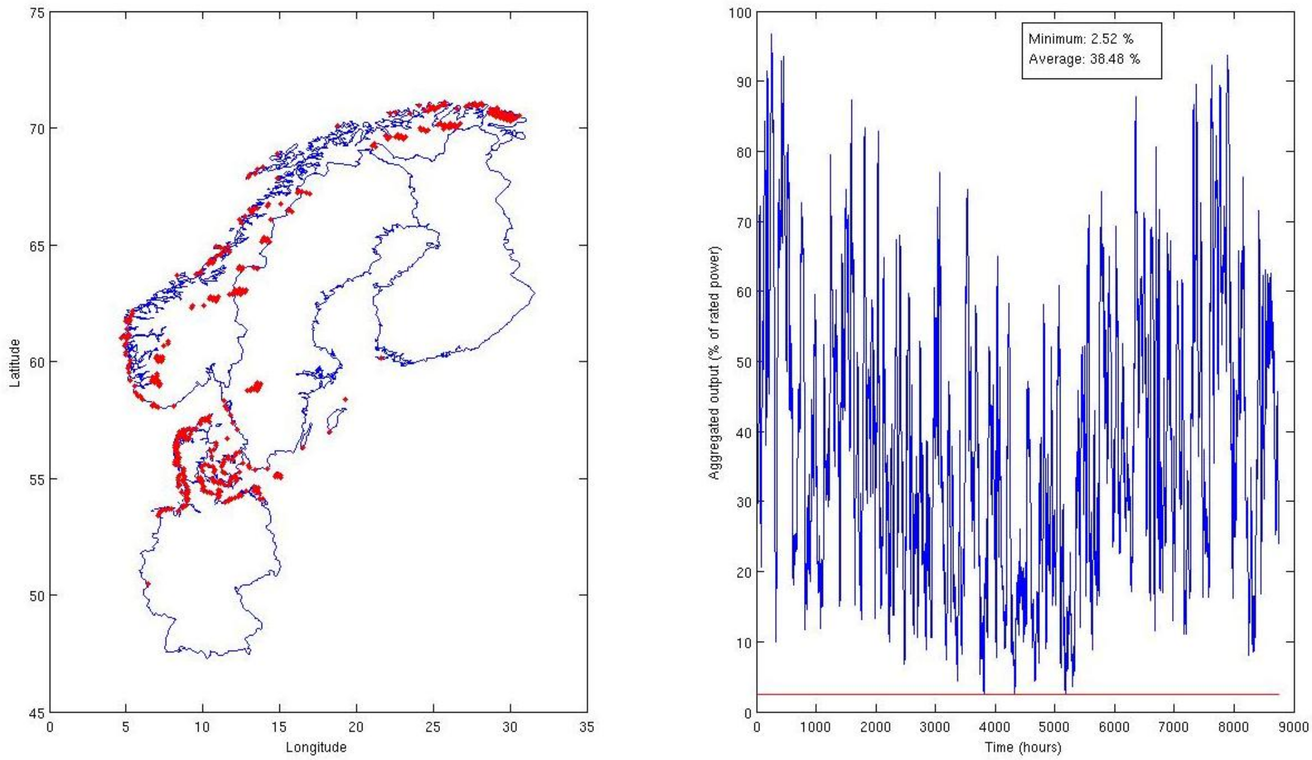

Fig. 4. a. The 400 sites with the highest output in the Nordic countries and Germany, and b. a time series for their aggregated output. The red line indicates minimum output during the year.

The wind data used here gives a higher average full load hours value per region than was obtained by the wind data used in [5]. This is expected, considering that in this work the 200 sites with the highest average yearly output are chosen to represent a region. The result that there are investments also in south-central Germany can be explained with that this generates a full load hour value for the German regions that are considerably higher, compared to what was obtained in [5]. However, transmission costs are the same, so the ratio of transmission cost to wind energy cost is higher. Thus, the cost for transmission is relatively higher than in the previous model runs, leading to that for the wind conditions applied in this work, it is more profitable to allocate investment near load centers, where no transmission is needed.

B. *Assessment of aggregated wind power production*

Figure 4a shows the combination of sites that yield the highest minimum output over the year together with the corresponding time series for this system (Figure 4b). The average power output (capacity factor) is 38.5 %, corresponding to 3,369 full load hours. The value of the minimum output, which is 2.52 %, is shown as a red line. The probability for this wind allocation to have an output of less than 10 % is 0.045. For comparison, the capacity factor of all points (even distribution of plants) in the five countries is 19.8 %, with a minimum output of 1.44 % and probability of 0.23 to have an output of less than 10%.

Thus, even though it has been suggested to be a smoothing effect due to declining correlation coefficient of wind power fluctuations with distance [7], the present results indicate that such a cross-correlation analysis is not sufficient to understand the relation between wind power plant allocation and the total variability from the aggregated wind power plants, which seems to be in line with the conclusion by Kiss and Janosí [4]. Yet, more work is required to further investigate possibilities to investigate the potential to smoothen aggregated wind power production with respect to geographical allocation. High spatial resolution in wind data should then be of major importance.

4. Conclusions

Detailed wind power data were used as input to a model which minimizes the sum of running costs to meet the heat and power demand and the wind power and transmission investment costs necessary to reach a wind power production level of 20% in Northern Europe. The results indicate that:

- It is cost-effective to allocate wind power in sites with a high yearly average output, such as Southern Norway, even considering the cost for transmission.
- When the ratio cost for transmission to cost for wind power goes down (which is the case when sites are chosen so that wind power output increases), there is a tendency towards allocating wind investments closer to load centers.

The assessment of the wind data indicates room for improvement in terms of the aggregated wind power capacity factor. Yet, it seems less likely that it is possible to find an allocation strategy that substantially reduces the variability of the power output.

Obviously more work is required to understand the possibilities and barriers of large scale introduction of wind power such as assessing possibilities with energy storage devices which can moderate the amount of transmission capacity required.

Acknowledgement

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