

Capacity Value of Wind Power, Calculation and Data Requirements: the Irish Power System Case

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Capacity Value of Wind Power, Calculation and Data Requirements: the Irish Power System Case

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Abstract—The capacity value of wind power indicates the extent to which wind power contributes to the generation system adequacy of a power system. The related data requirements may be subject to difficulties due to the temporal variability and spatial distribution of wind power in connection with the limited databases currently available. This paper presents a methodology to identify the minimal amount of data required for reliable studies. Based on wind power data of 74 stations in Ireland, covering up to 10 years, the effects of different numbers of stations and different time periods of data on the capacity value are analysed. The calculations are performed by means of a fast calculation code. The results show that at least 4 to 5 years of data in an hourly resolution are necessary for reliable studies and that 40 to 50 evenly distributed stations give an acceptable representation of the total wind power generation in Ireland.

Index Terms—wind power, capacity value, capacity credit, capacity factor, power system reliability

I. INTRODUCTION

RELIABILITY is an important feature of power systems. It is concerned with the ability of the power system to carry out its function of delivering electricity to the consumer. Reliability analyses consider two distinct aspects: adequacy and security. The capacity value relates to system adequacy, i.e. the existence of sufficient facilities within the system to satisfy demand [1]. As the installation of power plants is a long process, future power portfolios and their ability to cover the demand must be assessed in advance. The contribution of wind power to the availability of generating capacity becomes important with increasing wind penetration. The capacity value of wind power is therefore identified for future, potentially large wind power penetration levels.

Capacity value specifically designates the contribution of a power plant to the generation system adequacy of the power system. It gives the amount of additional load that can be served in the system at the same reliability level due to the addition of the unit. It is a long established value for conventional power plants [2]. Over recent years similar values have been calculated for wind power. The capacity values of countries, [3], [4], or even continents have been assessed [5]. More specialised analyses consider, for example, system reliability in the optimization of geographical distribution of

wind farms [6], or in the optimization of future generation portfolios [7]. An overview of different studies was given in [8]. Different definitions of capacity value have been applied in the studies. Basic definitions are compared in [9], [10] and the possible approaches are typically differentiated between probabilistic and chronological [11], [12]. Here, a definition following the classic one by Garver [2] is used.

Synthetic time series have been proposed in the literature as a means of reconciling the sometimes limited availability of historical wind time series [13]–[15]. This work has focused on sequential Monte Carlo simulation to provide accurate frequency and duration assessment of wind power. The wind is modeled using an autoregressive moving average model, which captures the correlation between different wind sites. This approach is promising, provided that it can account fully for the relationship between wind availability and load. A key factor is capturing the effect of the underlying weather which drives not only wind output but also the load.

Historically, one problem of capacity value calculations has been their computational burden, however this problem has been ameliorated by the increasing processor capability of modern desktop computers. Several approximation methods were proposed in this context [16], [17]. As a vast amount of calculations had to be performed for the analyses in this paper, a fast code for exact capacity value calculations was implemented. A description of the code can be found in Section II.

The available data sets of wind power generation are often limited. The recent development of modern wind power, metering complexity and confidentiality issues are possible reasons. In connection with the spatial distribution of wind power, a challenge that arises is that capacity values are normally calculated for future installation levels without knowing future spatial locations of many of the wind farms. Often, their corresponding wind time series are unknown as well. Indeed, only time series data for a limited number of stations are generally available and the resulting aggregated time series are scaled to the assumed future capacity. The wind time series are thus only partially correlated and the upscaled time series may not lead to correct capacity values. A critical question, therefore, is the number of wind stations that is necessary for a satisfactory representation of the future wind power capacity value.

The limited data is also critical in connection with the temporal variability of wind power. The information given by studies based on certain time periods may not be applicable to other time periods. This is especially critical as the load is varying and the calculated capacity value depends strongly

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on the correlation of wind and load. Wind may contribute at the peak hours in one year and not in another [18]. A higher correlation between wind and load will lead to higher capacity values. This raises the question of the minimal period of investigation that is necessary for capacity value calculations. This question may also be relevant for conventional power plant capacity values due to the time-dependent load. The temporal resolution of the data, for example hourly or quarter-hourly, is another issue in this context.

Here, the questions, described above, regarding the spatial and temporal data requirements are addressed based on measured data. The definition of capacity value and its calculation are presented in Section II. Wind and load data of the Irish system is employed. The data as well as the applied power plant portfolio and reliability target are presented in Section III. Temporal aspects including temporal resolution and length of period of investigation are examined in Section IV. Spatial aspects of capacity value including the impact of the number of stations and different geographical patterns are examined in Section V. In each case the observed deviations of capacity value are also compared to the corresponding deviations of capacity factor. The capacity factor is thereby defined by the ratio between the energy generated over a period of time and the energy that would have been generated by constant operation at nameplate capacity. Section VI gives a sensitivity analysis. First the influence of LOLE, power plant portfolio and peak hours on the capacity value is analysed. Then the sensitivity of the results to different load profiles is checked. The conclusions of the paper is presented in Section VII.

II. CAPACITY VALUE CALCULATION

Capacity value stands for the effective load carrying capability presented by Garver [2]. It is defined as the increase of the system load carrying capability at a fixed loss of load expectation level due to the addition of a new generator. The loss of load expectation (LOLE) is a measure of generation system adequacy and nominates the expectation of a loss of load event.

For each conventional power generator a forced outage rate represents the probability of its outage. A convolution leads to a cumulative probability function stating the probability of each possible generation state [1]. The probabilities of available conventional generation are used in conjunction with the load time series to compute the LOLE. Wind power is introduced as negative load and LOLE is calculated once again based on the resulting effective load. As the new LOLE will be lower than the original one, additional load can be added. Through an iterative process the exact amount of additional load that leads to the original LOLE is determined and it is equal to the capacity value of wind power.

The convolution that leads to the probability function of generation can be calculated as follows. The probability functions are represented by a table composed of the vectors \mathbf{p} and \mathbf{c} giving the probability p_j for each capacity level c_j . In the first step it is given by the capacity and forced outage rate of the first power plant. In each step i a new power plant with capacity c^* and forced outage rate p^* is added according

to (1). The resulting probabilities and capacity levels are given by the vectors \mathbf{p}' and \mathbf{c}' . The corresponding table is twice as big as the old one and it will normally contain rows with equal capacity levels.

$$[\mathbf{c}^i \quad \mathbf{p}^i] \rightarrow \begin{bmatrix} \mathbf{c}^i + c^* & \mathbf{p}^i \cdot (1 - p^*) \\ \mathbf{c}^i + 0 & \mathbf{p}^i \cdot p^* \end{bmatrix} \rightarrow [\mathbf{c}' \quad \mathbf{p}'] \quad (1)$$

The rows with equal capacity levels have to be merged to avoid an exponential increase of the table size over the iterative process (the table would for example have more than 1 billion rows after 30 power plants). Rows with equal capacity levels are merged by summing up the associated probabilities. This merging after each iteration makes the calculation time consuming. A fast merging code was therefore implemented. First, the table is sorted in ascending order of the capacity levels using some pre-implemented sorting function according to (2). The resulting vectors are given by \mathbf{p}^s and \mathbf{c}^s .

$$[\mathbf{c}' \quad \mathbf{p}'] \xrightarrow{\text{sort}} [\mathbf{c}^s \quad \mathbf{p}^s] \quad (2)$$

Then, the temporary vectors \mathbf{h} , \mathbf{k} and \mathbf{q} are calculated according to (3). \mathbf{h} stands for the vector of the cumulative sums of the probabilities subtracted from 1. \mathbf{k} gives the differences between adjacent capacity levels. If the differences are zero the capacity levels are equal. \mathbf{q} is equal to \mathbf{h} but without the rows where \mathbf{k} is zero.

$$\mathbf{h} = 1 - \begin{bmatrix} 0 \\ p_1^s \\ \vdots \\ p_1^s + \dots + p_{n-1}^s \end{bmatrix}, \quad \mathbf{k} = \begin{bmatrix} 1 \\ c_{2,\dots,n}^s - c_{1,\dots,n-1}^s \end{bmatrix} \quad (3)$$

$$\mathbf{q} = \mathbf{h}_{j|k_j \neq 0}$$

Finally the new vectors of capacity levels and probabilities \mathbf{c}^{i+1} and \mathbf{p}^{i+1} are calculated by (4). All capacity levels in \mathbf{c}^{i+1} are different keeping the size of the table as small as possible.

$$\mathbf{c}^{i+1} = \mathbf{c}_{j|k_j \neq 0}^s \quad \text{and} \quad \mathbf{p}^{i+1} = \begin{bmatrix} \mathbf{q}_{1,\dots,m-1} - \mathbf{q}_{2,\dots,m} \\ q_m \end{bmatrix} \quad (4)$$

After all iterations the probability function of conventional generation capacity is known.

Another principal step in iterative capacity value calculations is the calculation of LOLE. A possible notation is given by (5). F_C stands for the cumulative distribution function of conventional generation capacity. $F_C(x)$ gives the probability that generation capacity to the extent of x or less is available and l_t stands for the load level at time step t . $F_C(l_t)$ gives the loss of load probability at time step t and summing up over all time steps, T , leads to the LOLE in the considered time period.

$$LOLE = \sum_{t=1}^T F_C(l_t) \quad (5)$$

The equation assumes independence between load levels and capacity outages and their associated probabilities as is usual. Capacity outages are thereby not only independent from load but also independent from each other. Load data is here given in the form of a time series with T time steps.

Wind power is introduced as negative load. For each time step t the load l_t is reduced by the wind power generation w_t resulting in the net load, $e_t = l_t - w_t$. To calculate the capacity value, (constant) load is then added until the original level of LOLE is reached. In other words, the added load is equal to the capacity value (cv) if the LOLE based on the net load plus the additional load is equal to the LOLE based on the original load. This can be expressed as follows.

$$LOLE_{Ref} = \sum_{t=1}^T F_C(l_t) = \sum_{t=1}^T F_C(e_t + cv) \quad (6)$$

$F_C(l_t)$ is a simple table look-up process. Its computation is fast once F_C is known. The value of cv is determined by iterative calculations of $LOLE$. The number of iterations can be reduced by adapting the process of load adding. Therefore the algorithm shown in Fig. 1 was developed (many other algorithms, for example according to the bisection method [19], may be possible).

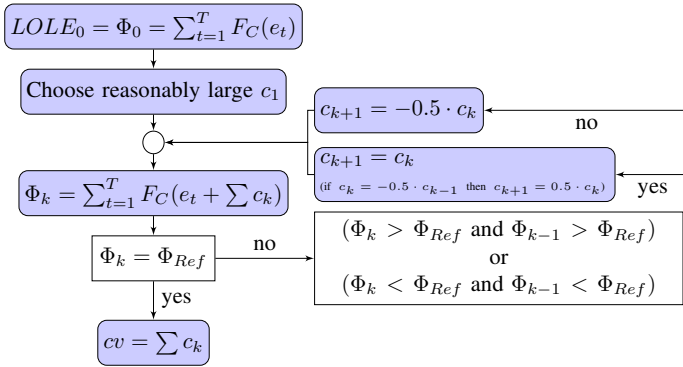


Fig. 1. Algorithm of capacity value calculation by iterative load adding

The code was implemented in Matlab. On a standard notebook computer (Core 2 Duo T9300, 2.5 GHz, 3 GB Ram) a capacity value calculation based on one year of fifteen minute resolution data and 50 conventional power plants and including the calculation of F_C takes between 0.1 and 0.3 seconds. The calculation of F_C itself takes about 0.05 seconds. In a test case of 500 conventional power plants, the calculation of F_C takes about 8 seconds.

III. SYSTEM DESCRIPTION

A. General Information

The analysis is based on the Republic of Ireland (ROI) power system. The total capacity of conventional power plants is modelled as 5,814 MW on the basis of [20], [21]. There are 50 units in total with capacities ranging from 4 MW to 480 MW. Forced outage rates are between 1% and 12%. The exact portfolio composition is given in Table I excluding the confidential forced outage rates. Quarter-hourly load-data was available covering the years from 1999 to 2008. Fig. 2 shows the mean load levels for each month and hour over ten years. The load of each year is scaled according to the reference LOLE as described below. There are large differences between day and night time. A high load peak can be observed in the evening hours over the winter months whereas the load profile is more flat over the summer months.

TABLE I
APPLIED POWER PLANT PORTFOLIO FOR IRELAND (ROI)

Unit Name	Capacity (MW)	Unit Name	Capacity (MW)
ROI-1	4	ROI-26	73
ROI-2	4	ROI-27	88
ROI-3	4	ROI-28	88
ROI-4	8	ROI-29	90
ROI-5	10	ROI-30	91
ROI-6	10	ROI-31	108
ROI-7	15	ROI-32	108
ROI-8	15	ROI-33	110
ROI-9	15	ROI-34	110
ROI-10	19	ROI-35	112
ROI-11	21	ROI-36	118
ROI-12	22	ROI-37	137
ROI-13	23	ROI-38	150
ROI-14	23	ROI-39	163
ROI-15	24	ROI-40	241
ROI-16	52	ROI-41	241
ROI-17	52	ROI-42	242
ROI-18	52	ROI-43	258
ROI-19	54	ROI-44	285
ROI-20	54	ROI-45	285
ROI-21	54	ROI-46	285
ROI-22	54	ROI-47	343
ROI-23	73	ROI-48	396
ROI-24	73	ROI-49	404
ROI-25	73	ROI-50	480

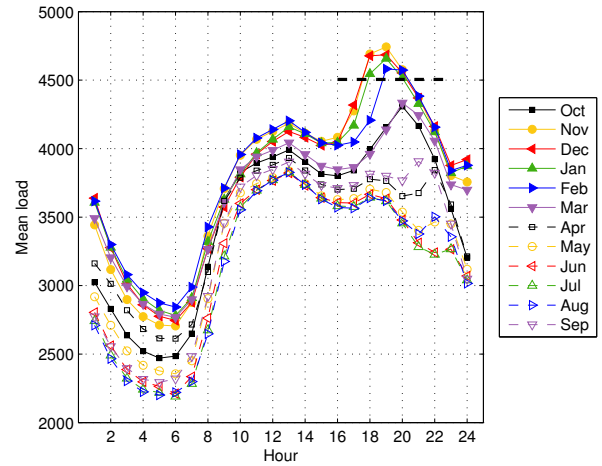


Fig. 2. Mean load levels over ten years after scaling (1999 - 2008) (dashed line indicates peak hours for Section VI)

The unscaled load data shows a strong increase of yearly LOLE due to a strong increase of the total demand over the later years. Applying the power plant portfolio above the LOLE increases from 1 second in 1999 to over 2 hours in 2008. In contrast to these values a reference LOLE of 8 hours per year is chosen (nominated as L1) according to the calculation standards in Ireland [22]. In the sensitivity analysis in Section VI, a lower reference LOLE is also applied.

Before all capacity value calculations the load of each year has to be scaled so as they all start at the same reference LOLE. The load is therefore multiplied by a constant scaling factor. The scaling factor is determined in an iterative process calculating the LOLE after each iteration. This scaling is necessary in order to examine the wind data requirements for reliable capacity value calculations and because the capacity value of a power plant is always calculated in reference to a certain LOLE only. Otherwise, the differences of wind capacity values in different years would not only be due to the wind data but also due to the different initial LOLEs. Without

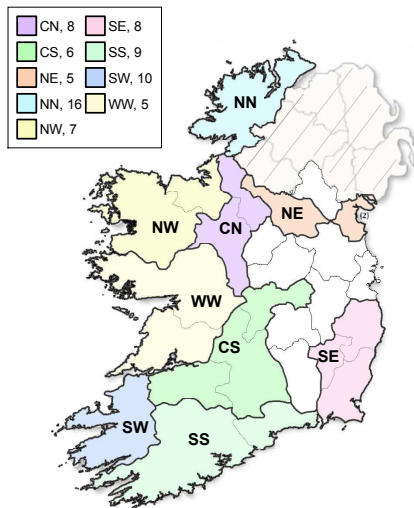


Fig. 3. Considered regions in the island of Ireland

scaling, even a conventional power plant would have different capacity values in different years even though its FOR stays the same. For the purpose of comparison, the power plant portfolio is also assumed to stay the same over all years.

B. Wind Data

The quarter-hourly measured wind power data of 74 wind farms in Ireland was used. The longest data arrays span from 1999 to 2008, covering 10 years with the shortest covering 2008. In 2008, the total capacity of the 74 wind farms was 772 MW and they had a capacity value of 222 MW. For the rest of the paper, all series are normalized by their nameplate capacities and in all analyses the installed capacity is assumed to be equal at all stations. This is necessary for unbiased comparisons between different stations. In realistic studies the stations should obviously represent the capacities that are installed in the corresponding regions.

The wind farms are distributed over many areas of Ireland. Fig. 3 indicates the regions they are situated in. The number of stations in each region is given in the legend. There are at least 5 stations in each region. The area of Northern Ireland in the north east of the island is not considered here as a consistent data set was not available.

Fig. 4 shows the mean capacity factors for each month and hour over ten years based on 6 wind stations. In the winter months wind yield is high and relatively independent from the hour of day. However, in the summer months it is low but with a peak in the late afternoon. Two wind penetration levels are used here for the result, 1,000 MW and 4,000 MW. The first value gives approximately the present installed capacity in Ireland. The second one is a common assumption for the installed capacity in 2020 [20].

IV. RESULTS: TEMPORAL ASPECTS

The available data for capacity value calculations is defined by its spatial and temporal characteristics. There are two temporal aspects. The temporal resolution of the data may be limited and the data will only cover a certain time period.

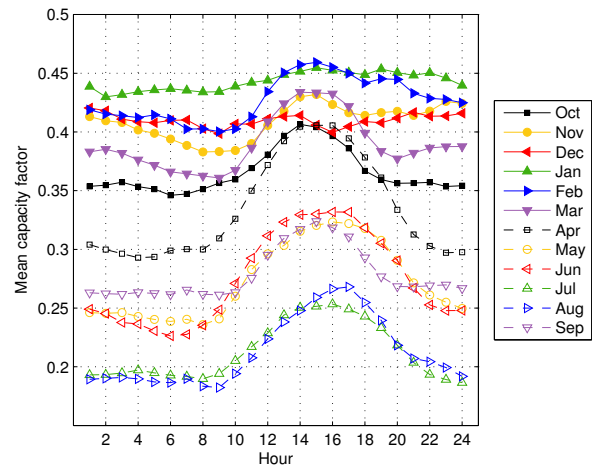


Fig. 4. Mean wind capacity factors over ten years (1999 - 2008)

A. Temporal Resolution

A typical temporal resolution for wind data is one hour, but there are also wind data sets that only have values every six hours [23]. Even if data of a high resolution is available lower resolutions might be acceptable for reasons of data handling and calculation time under the condition that results are not affected. The quarter-hourly data that was available allows to examine the impact of such lower temporal resolutions on capacity value calculations.

Fig. 5 shows the extent to which the capacity value is affected by the resolution for an installed capacity of 1,000 MW and 4,000 MW. The year 2008 with all stations is considered here. Data points every 1/4, 1/2, 1, 2, 3, 4, 6 and 12 hours are selected. Depending on the resolution, there are different possibilities of data selection. If, for example, data points are selected on an hourly resolution, there are four different data arrays possible. For each data array, the capacity value is calculated and compared with the capacity value based on a quarter-hourly resolution. The resulting deviations are given by the small dots in Fig. 5 for the 1,000 MW case. The maximal deviations are thereby indicated by the large dots on the solid line. In addition, the dashed line with crosses indicates the maximal deviations for the 4,000 MW case.

Capacity values based on data sets that record only every three hours or less can be significantly different to the capacity value of quarter-hourly data. Deviations of up to 5% are for example still possible for a 3 hour resolution, but it can be seen that hourly data leads to representative results and deviations are below 1% in all cases. Depending on the required accuracy, hourly data is a good starting point for calculations even though higher resolutions are preferred if possible.

B. Period of Investigation

Often, long data series of wind power are not available and system studies are based on a few years of data [21], [24]. However, longer data sets might be necessary for more general results. Wind power data of six stations situated in the regions 'NN', 'NW' and 'CN' was available for ten years

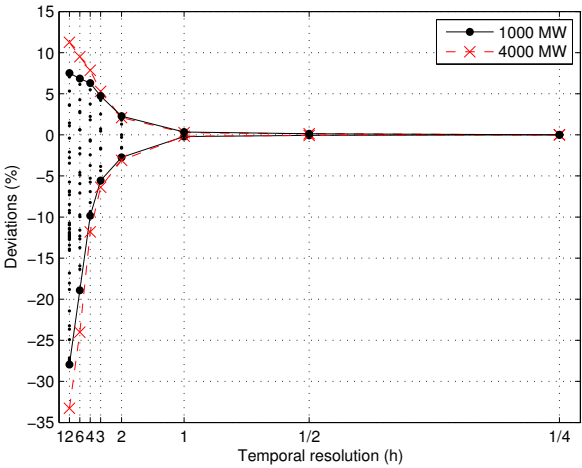


Fig. 5. Deviation of capacity value over temporal resolution compared to result with quarter-hourly data

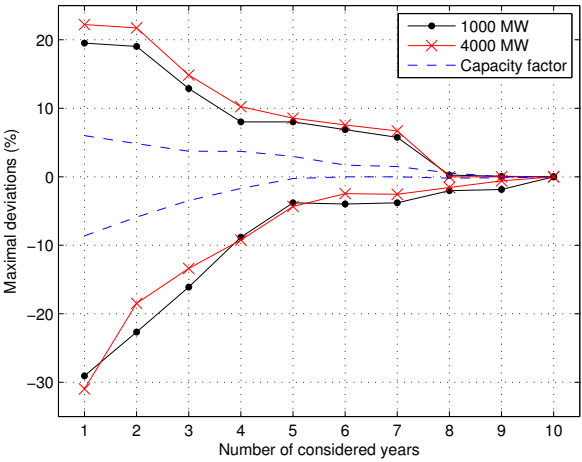


Fig. 7. Deviation of capacity value and factor over number of years compared to result with 10 years

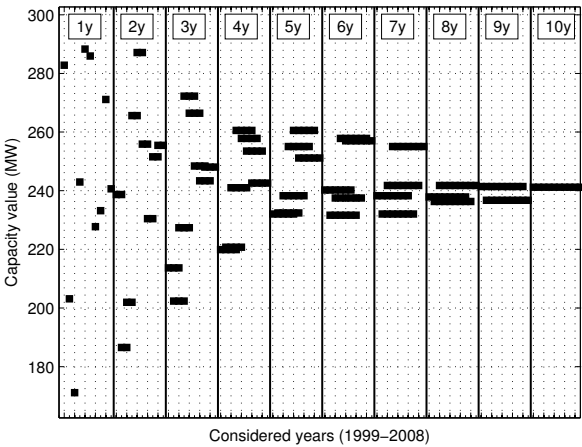


Fig. 6. Capacity value over different time periods (1999 - 2008) for an installed capacity of 1000 MW

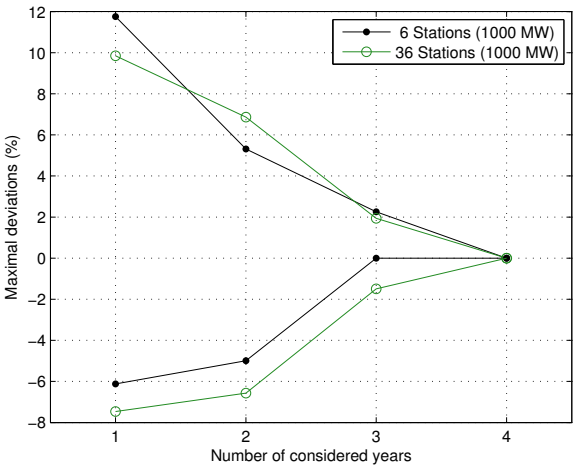


Fig. 8. Deviation of capacity value over number of years compared to result with 4 years

and is used here to assess the data requirements for a capacity value calculation that is representative from a medium-term perspective. The time series allow an analysis of possible discrepancies between calculations based on shorter data sets compared to a reference result based on 10 years. Medium term aspects are covered by 10 years of data. Long term aspects such as changing wind power resource due to climate change cannot be analysed here [18].

In Fig. 6 capacity values for varying number of years are plotted assuming that the six stations represent 1,000 MW of installed capacity. The first column shows capacity values calculated using one year of data. In the second column capacity values based on two consecutive years are shown. The line in the last column stands for the reference capacity value calculated using all data. The calculations based on one year of data show large variations. As mentioned in Section III the load of each year is scaled according to the reference LOLE value before the calculations. The differences in the results

are therefore only due to the wind data and the correlation of wind and load, but not due to the load level.

Fig. 7 shows the maximal possible deviations depending on the number of considered years for the installation levels of 1,000 MW and 4,000 MW. If only one year of data is applied, underestimations by about 30% or overestimations by about 20% are possible. Even with 3 years of data significant deviations are still present. Only with 4 or 5 years of data do deviations not exceed 10%. These indications refer only to the maximal possible deviations and they are relatively probable. In the case of one year of data the risk of having such an extreme deviation is, for example, at least two in ten (as the analysis above is based on ten years and there is one year with a maximal result and one with a minimal result). It should also be noted that the maximal yearly capacity value is about 1.7 times the minimal one, so nearly twice as high.

A possible explanation for these large deviations could be that the calculations are based on data of six stations and that

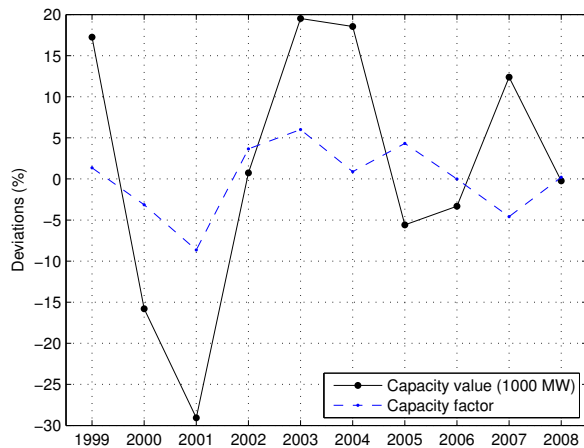


Fig. 9. Yearly deviations of capacity value and factor compared to result with 10 years

the temporal differences are more accentuated for six stations than for wind power profiles based on many stations. To check this hypothesis the same calculations were performed based on 4 years of data ranging from 2005 to 2008, once for the 6 stations and once for 36 stations. The 36 stations are located in all regions and include the 6 stations. Fig. 8 shows that the deviations are similar. Hence, the hypothesis does not hold. A systematic decrease of deviations with more stations is not observed.

C. Capacity Factor and Capacity Value

The changes of capacity factors and with it wind power production over different years are well documented [25]. Wind indices state to what extent years can be seen as typical in relation to a longer time period. This is of crucial importance for wind farm projects. It is therefore of interest to relate the deviations in capacity value to deviations in capacity factor. The capacity factor thereby gives the ratio between the actual generated energy and the energy that would have been generated by a constant operation at nameplate capacity.

In Fig. 7 the maximal possible deviations of capacity factor are plotted with the capacity value deviations. The capacity factor deviations are well below the capacity value deviations and smaller than 10%. The figure does not show how the deviations of capacity value are related to the corresponding deviations of capacity factor.

Fig. 9 shows the deviations of capacity factor and capacity value related to the corresponding values over 10 years. They are only weakly correlated. The correlation of the deviations is 0.6 and it is similar in the case of 4,000 MW. In 2004, for instance, an average capacity factor is observed whereas the capacity value is nearly 20% above the result with 10 years of data. Also, the signs of the deviations do not always correspond and low wind output years can lead to high capacity values as in 2007.

At the beginning of this section, the impact of temporal resolution on the capacity value was examined, see Figure 5.

The same analysis was done for capacity factors. The capacity factor is only slightly affected by the temporal resolution. The capacity factors differ only by -4% to +3% from the quarter-hourly result, in contrast to the -35% and 15% in Figure 5.

V. RESULTS: SPATIAL ASPECTS

In this section the dependencies of capacity value on different spatial wind data settings are examined. Often regional wind power output is simulated by wind time series profiles of a limited number of wind stations, however, the accumulated output of these stations may not be representative for the total wind power in the region. Normally wind farm locations will be selected that are distributed over the whole region in order to get a representative profile. The required number of stations for this case is addressed first. The second section addresses the case that the wind farms are only located in a few areas of the regions.

A. Number of Stations

The possible errors of capacity value calculations occurring with a limited number of wind station data applied are assessed first. The data of 2008 with all wind stations was used (74 stations, scaled in order to have the same capacity). Their accumulative time series is taken as representative for Ireland. Capacity value calculations that are based on less stations will lead to different results. The possible mean errors are estimated as follows.

Random combinations of stations are drawn such that there is an equal number of stations in each region in Fig. 3. As there are nine regions and there are only 5 stations in some regions, combinations of 9, 18, 27, 36 or 45 stations are taken. The capacity values of all possible station combinations cannot be calculated as there are too many. In the case of 9 stations, for instance, there are more than 96 million possible combinations. In each case only 250 combinations are randomly drawn and their capacity values are calculated.

The station combinations that lead to the most extreme deviations are not captured by such a random approach. The extreme combinations are therefore identified in a different way. In the first step, all combinations with two stations (out of different regions) are taken. The combination that leads to a maximal (or minimal) capacity value is kept and a third station is added. Thereby all possibilities are again considered but the different regions can only be represented by an equal number of stations. The combination leading to a maximal (or minimal) value is determined and a new station is added. At the final step there are 53 stations with 5 stations in region WW and NE and 6 stations in every other region. Thus, estimates of the extreme combinations are derived, but it cannot be strictly excluded that "more extreme" combinations exist (for example, if the extreme combination of three stations does not include the extreme combination of two stations).

All calculated capacity values are shown in Fig. 10 for an installed capacity of 1,000 MW. The results based on random combinations are plotted for 9, 18, 27, 36 or 45 stations. The extreme results are plotted for all numbers of stations. The stations are evenly distributed as they are, as far as possible,

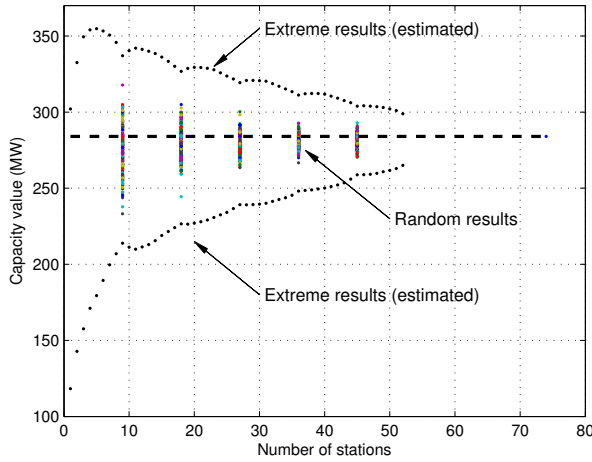


Fig. 10. Capacity value over number of evenly distributed stations for an installed capacity of 1000 MW

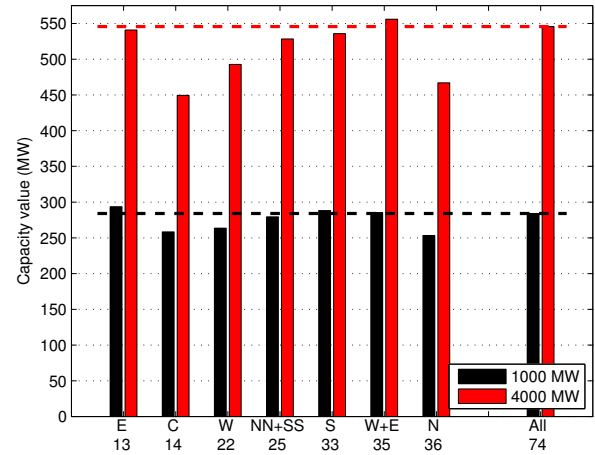


Fig. 12. Capacity value for different regions

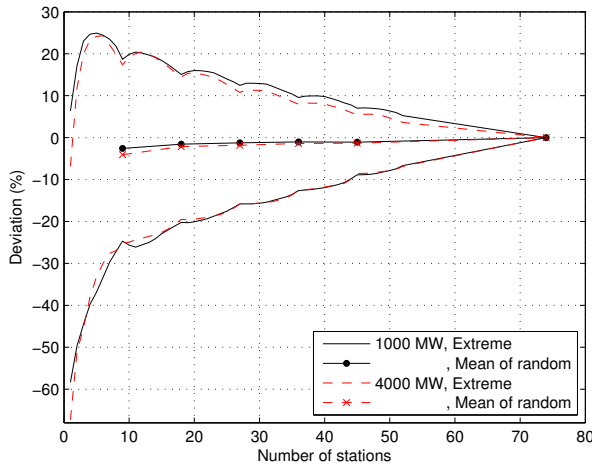


Fig. 11. Deviation of capacity value over number of roughly evenly distributed stations compared to result with 74 stations

taken from different regions. The capacity value of all stations is indicated by the dashed line. Interestingly the random results do not reach the extreme results. This means that there are only very few stations combinations that lead to extreme results. Assuming, for example, that 2% of all station combinations N lead to extreme results. The probability that none of them occurs in a sample of 250 combinations is as follows:

$$P_{\text{No extreme combination}} = \frac{\binom{0.98 \cdot N}{250}}{\binom{N}{250}} \quad (7)$$

In the case of 9 stations N is equal to 96,768,000 and P becomes 0.0064. So, there is only a small probability to have a sample that does not include an extreme combination. As the random results do not reach the extreme results in several test samples, the percentage of extreme combinations must be even lower than 2%. Hence, the probability that a certain station combination leads to an extreme capacity value is very small.

Fig. 11 shows the percentage extreme deviations in positive and negative direction and the mean deviations for 1,000 MW and 4,000 MW. On average, applying fewer stations to the calculation leads to lower capacity values. The possible extreme deviations are high at the beginning and become lower with increasing station numbers. With 40 stations the highest possible deviations are nearly at 10%.

B. Pattern of Stations

In Fig. 11 all stations were equally distributed over the existing regions. Now, only stations of selected regions are considered for capacity value calculations. Region names are according to Fig. 3. For example, region 'W' includes regions 'WW', 'SW' and 'NW'. The results in Fig. 12 are for capacity levels of 1,000 MW and 4,000 MW. The second line below the x-axis indicates the number of stations in the region.

In general, capacity values of single regions are lower than those based on all stations in the system (indicated by the dashed line). The small number of stations is not the only reason for this. The capacity value for region 'N' is, for example, lower than typical values for 36 equally distributed stations (see mean deviations in Fig. 11). These influences are due to different wind patterns at different spatial locations and therefore decreasing correlations of wind profiles with increasing distances [26]. Correspondingly, regions like 'NN+SS' or 'W+E' composed of different parts of the island have similar capacity values as the one based on all stations. The same is true for region 'S' which covers the east and west coast. Hence, if the wind patterns at distant parts of a considered region are captured, the influence of wind stations located in between is less important.

Capacity value also depends on other factors. The capacity value of region 'E', being of relatively small size with few stations, is almost equal to the one for all stations. This can be explained by its higher capacity factor given in Table II in the next subsection.

C. Capacity Factor and Capacity Value

The deviations of capacity values can be connected to capacity factors, as done in the temporal analysis. The capacity factors of the random combinations in Fig. 10 were related to the capacity factor of all stations. The resulting deviations were then compared to the corresponding deviations of capacity value. For 1,000 MW the correlation coefficient between deviations of capacity factor and capacity value is 0.90. In comparison, it is 0.65 in the case of 4,000 MW. Hence, capacity factor and capacity value are only strongly correlated if the installed wind capacity is relatively small. The differences between regional capacity values or regional

TABLE II
REGIONAL CAPACITY VALUE AND CAPACITY FACTOR DEVIATIONS
COMPARED TO RESULTS WITH ALL STATIONS (%)

	E	C	W	NN+SS	S	W+E	N
1000 MW	3.4	-9.0	-7.2	-1.6	1.4	0.5	-10.8
4000 MW	-0.9	-17.6	-9.7	-3.2	-1.8	1.9	-14.4
CapFac	7.5	0.0	-4.8	0.4	3.7	-0.2	-2.1

capacity factors and corresponding all station values are given in Table II. The capacity factors are quite similar to the capacity factor based on all stations, differing only by up to 7.5% (all stations together have a capacity factor of 0.35). In regions that are more spread, such as 'NN+SS', 'S', and 'W+E' only small capacity value deviations are seen, even though their capacity factor deviations are not small compared to the other regions.

VI. SENSITIVITY ANALYSIS

It is important to bear in mind that the capacity value of wind power can be influenced by many factors, such as the wind penetration, chronological wind generation and its correlation with load, spatial wind generation (e.g. offshore) and the generation portfolio. Beyond the methodology of this paper, there are aspects related to scheduling of planned outages, definition of reliability, demand growth, system expansion, topology and more. Hence, each power system is unique and there is not a "generic" system.

The following sensitivity analysis attempts to check the robustness of the results and to what extent they may have general applicability. The test cases are however limited and, most important, always based on the Irish wind data and its correlation to the load. The results may therefore not be valid for other power systems. First, a different power plant portfolio and a different reliability level are applied. Secondly, the influence of the load profile is examined by modifying the load data to more extreme load profiles without changing the correlation between wind and load.

A. Influence of System Configuration

The IEEE reliability test system in its two-area configuration is chosen as an alternative power plant portfolio and structure. It consists of the 64 units in Table III having a total capacity of 6,810 MW. Units sizes are between 12 MW and 400 MW,

TABLE III
IEEE RELIABILITY TEST SYSTEM - 1996 (TWO AREA)

Unit Name	Capacity (MW)	FOR	Unit Name	Capacity (MW)	FOR
U12	12	0.02	U12	12	0.02
U12	12	0.02	U12	12	0.02
U12	12	0.02	U12	12	0.02
U12	12	0.02	U12	12	0.02
U12	12	0.02	U12	12	0.02
U20	20	0.1	U20	20	0.1
U20	20	0.1	U20	20	0.1
U20	20	0.1	U20	20	0.1
U20	20	0.1	U20	20	0.1
U50	50	0.01	U50	50	0.01
U50	50	0.01	U50	50	0.01
U50	50	0.01	U50	50	0.01
U50	50	0.01	U50	50	0.01
U50	50	0.01	U50	50	0.01
U50	50	0.01	U50	50	0.01
U76	76	0.02	U76	76	0.02
U76	76	0.02	U76	76	0.02
U76	76	0.02	U76	76	0.02
U76	76	0.02	U76	76	0.02
U100	100	0.04	U100	100	0.04
U100	100	0.04	U100	100	0.04
U100	100	0.04	U100	100	0.04
U155	155	0.04	U155	155	0.04
U155	155	0.04	U155	155	0.04
U155	155	0.04	U155	155	0.04
U155	155	0.04	U155	155	0.04
U197	197	0.05	U197	197	0.05
U197	197	0.05	U197	197	0.05
U197	197	0.05	U197	197	0.05
U350	350	0.08	U350	350	0.08
U400	400	0.12	U400	400	0.12
U400	400	0.12	U400	400	0.12

forced outage rates reach from 1% to 12% The alternative LOLE (nominated as L2) is 8 hours in 10 years in accordance with the LOLE target of having one day with an outage over 10 years. As system planning studies often focus on peak hours, capacity values are here also calculated for those hours only. They are identified in Fig. 2 in Section III where 95% of the maximal mean load level is chosen as their critical load level. It is indicated by the dashed line. All hours that show higher mean load levels are considered as peak hours: 6 pm, 7 pm and 8 pm in November, December and January and 7 pm and 8 pm in February.

Fig. 13 shows the influence of the described system configurations on the general capacity value. Calculations are based on the quarter-hourly data of all wind stations and load in 2008. 'ALL' refers to calculations based on all hours whereas 'PEAK' refers to calculations based on peak hours. L1 and L2 refer to reference LOLEs of 8 hours in 1 year and 8 hours in 10 years, respectively. Relative capacity value decreases strongly with increasing installed capacity. For better illustration the rectangle zooms in on the results at 3,500 MW separately for the Irish plant portfolio (ROI) and the IEEE test system. In general the capacity value is 0.01% to 0.02% higher in the IEEE test system. The application of the higher reference LOLE, L1, results also in higher capacity values. The influence of peak hours is less clear. The restriction to peak hours in the calculation leads to slightly higher results in the IEEE system, but to slightly lower results in the ROI system.

The different system configurations were also applied for all other calculations of the paper. In general, the results are similar. In Fig. 7, larger differences are observed for the temporal deviations that derive with time periods of one or two years. In these cases, introducing L2 as the reference LOLE leads for example to increased deviations. The highest deviations are observed for the ROI system with an L2 LOLE

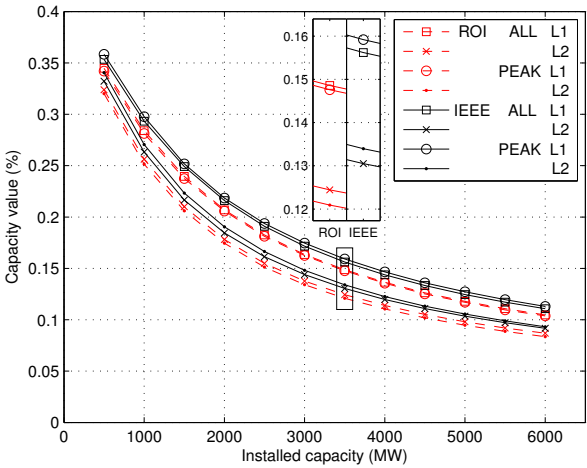


Fig. 13. Capacity value of wind for different system settings

and peak hours. An overestimation of 38% is then possible if only one year of data is applied whereas it is about 20% in Fig. 7 using L1, ROI and all hours. It can also be seen that for all system configurations the deviations come down to 10% with four or more years of data. Hence, the recommendation of using minimally 4 to 5 years of data is still valid. The temporal resolutions in Fig. 5 were also tested with different system configurations (but always with all hours). For all configurations deviations drop to less than 3% in the case of two-hourly data and 1% in the case of hourly data. Finally, the deviations depending on the number of stations were compared for the different system configurations. Very similar deviations are observed and regional output is well represented by 40 to 50 stations.

In these calculations the applied generation portfolio stayed constant over the considered time period but, in reality, the generation portfolio may change. Such changes could be considered in the calculation by several probability functions of conventional generation capacity that are applied to the related time steps in Equation (6). The variations of the capacity value between different time periods are then not only due to the wind profile and its correlation with load but also due to the portfolio changes. The results in Fig. 13 however suggest that such portfolio changes would only have a small impact on the capacity value.

B. Influence of Load Profiles

In the sensitivity analyses above the load and wind data are not changed, in order to maintain their correlation and the underlying common weather pattern. In this section, the load data is modified to check the robustness of the presented results. The original power plant portfolio and reliability level is used. Two points are considered in the modification. On the one hand, the influence of different daily and seasonal load profiles should be analysed. The load profile may for example be different due to a higher consumer sensitivity to temperature. On the other hand, a high consistency between the wind and load data should be kept. The following modifica-

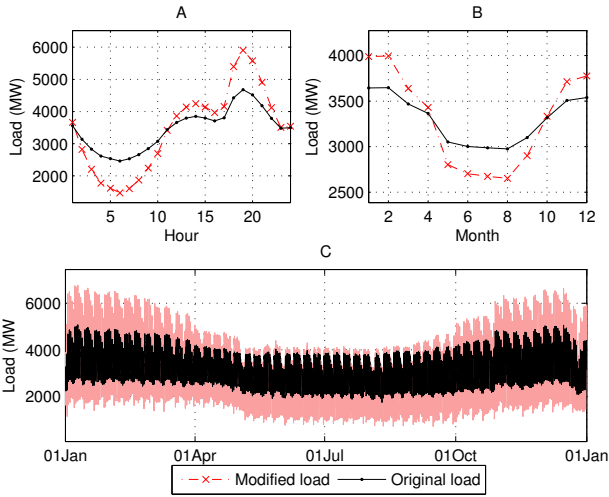


Fig. 14. Modifying of load (C) by combination of daily (A) and seasonal (B) scaling

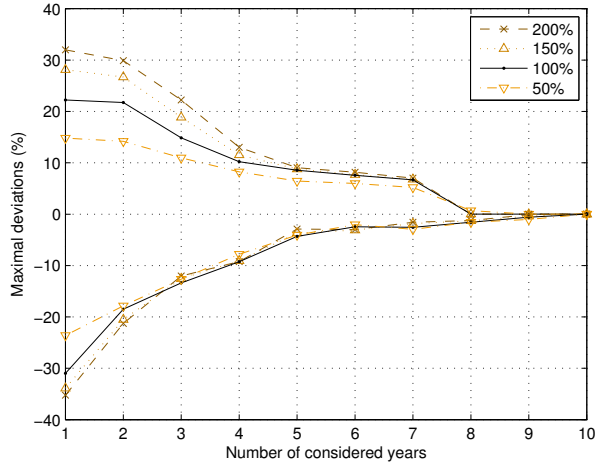


Fig. 15. Deviations of capacity value compared to result with 10 years

tion is therefore applied to the load data. In each time step the difference to the daily mean is scaled leading to more damped or accentuated load profiles without changing the total load. Additionally, in each year, the monthly mean loads and their difference to the yearly mean are considered. These differences and the related load data is then scaled leading to more damped or accentuated seasonal profiles, again without changing the total energy demand.

Fig. 14 illustrates the modification for a scaling of 200%. Fig. 14-A and B show the original and modified load levels for an example day respectively an example year. Fig. 14-C shows the resulting modified load and the original load for 2008. The difference between the maximum load and minimum load of the year changes from 3320 MW to 6057 MW due to the modification. The correlation between wind and load however changes only from 0.156 to 0.161. Each year is scaled correspondingly. Other scaling factors are 150% and 50%. The latter leads to a dampened load profile.

The results of Figure 7 in Section IV-B were reproduced

with the modified load profiles and the new results are shown in Fig. 15. The maximal possible deviations are shown depending on the number of considered years. An installed capacity of 4000 MW is assumed. The results are similar for all load profiles. Only with a low number of years there are larger differences. A more accentuated load profile leads to higher deviations whereas a dampened load profile leads to lower deviations, but in all cases the deviations drop to 10% with four or five years of data. These results suggest, that, even though the absolute capacity value may depend on the applied system, the relative differences between different years are similar in each system. Concluding, even with extreme load profiles the recommendation of four or better five years of data as a minimum holds.

VII. CONCLUSION

The influence of underlying data on capacity value has been analysed. A fast algorithm for capacity value calculation was developed that is suitable for large amounts of data. In combination with the data analysis a methodology is presented to identify the data requirements for reliable capacity value studies.

The effects of different temporal resolutions and time periods were examined. The analysis shows that robust results are achieved if the data has a temporal resolution of one hour or less. In the case of different time periods the risk of high deviations is more important. Deviations of results based on only one year of data can easily exceed 20% depending on the system configuration. No significant difference in the temporal deviations can be observed between 6 wind stations and 36 wind stations. A minimum of 4 to 5 years of data is shown to be a good base for stable calculations. This recommendation was checked with different system configurations and it also holds with modified load profiles. The deviations are related to a reference value which is based on 10 years and no long-term aspects are covered here. The conclusions therefore refer to assessing an average, medium term capacity value. The occurrence of low output wind years still has to be considered. A capacity value calculated in a good wind year might be nearly twice as high as it will actually be in a bad wind year. This makes calculations based on a limited number of years even more inadequate.

The presented results indicate that a limited number of stations in the calculations is less critical. On average, it leads to a slight underestimation of capacity value but in general the deviations are low. The maximal possible deviations are more important, however, they are not probable. This is true if each region is represented by at least 1 to 2 stations. By taking into account 4 to 5 stations per region (40 to 50 stations in total) the maximal possible deviations are also small. This applies to a reference value that is only based on 74 stations. Larger deviations may appear if the represented wind power consists of far more stations resulting in a much higher station density in the area. It also has to be considered that the geographical size of the applied system is relatively small.

The results of the sensitivity analysis suggest that the results related to the Irish system and their main conclusions have

general applicability, at least to systems with similar relationship between wind and load. Analyses of other systems, using the methodology developed here, will help to get a more global picture about the capacity value of wind power and the required data.

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