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Impact of Offshore Wind Power on System Adequacy in a Regional Hydro-based Power System with Weak Interconnections

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Abstract

This paper presents an innovative contribution in considering the combined effect of wind farms and grid transmission capacity on loss of load probability (LOLP), rather than just the effect of wind capacity alone. The demonstrated methodology can be generally applied in system adequacy studies for generation expansion and transmission planning. This is of high relevance for planning the power systems of the future with large offshore wind farms and strong transnational grids. The methodology is demonstrated using data from a real life regional hydro-based power system with a predicted need for new generation and/or reinforcement of interconnections to meet future demand. The region is in proximity to favourable offshore wind resources that can be an option for new generation. The question is if adding wind power to the hydro-based system will be sufficient or if additional measures must be taken to secure system adequacy. The paper concludes that wind power and grid expansion will have a positive effect on system adequacy. Wind power contributes to reducing the LOLP and can be attributed a capacity value. It shows that the smoothing effect due to geographical distribution of wind power contributes significantly to increasing the wind capacity value in systems with high penetration of wind energy. Further, the LOLP and wind capacity value are sensitive towards the assumed average wind power generation, but robust towards normal variations of the availability and power curve.

Keywords: Loss of load probability; Power system; Wind power; Grid

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1. Introduction

This paper considers the impact of offshore wind power on system adequacy. The impact is assessed using data from a real life regional hydro-based power system, though data are made anonymous and fitted for the purpose of this paper. The region has a predicted need for new generation and/or reinforcement of interconnections to meet future demand. Considering that the region is in proximity to favourable offshore wind resources the question is if adding wind power to the hydro-based system will be sufficient or if additional measures must be taken to secure system adequacy.

System adequacy relates to the ability of the system to meet the load demand. In this paper this is addressed considering the system's ability to meet the peak demand. This is assessed by calculating the loss of load probability (LOLP) for the system. The calculation takes account for the installed generation and transmission capacity, the probability of outages, and the probability of wind power generation at the hour of peak demand. The calculation method is further outlined in section 2. A critical point is the representation of the wind power in the peak load hour as a distribution. This is assessed in section 3. The case study specifications are given in section 4, thereafter results (section 5) and conclusion (section 6).

Indeed, it is well established that a more relevant measure for system adequacy than LOLP in the peak load hour is the LOLP over the full year, [12]. This measure can be determined following the same general methodology as outlined in this paper, but applying the load and wind distribution over the year rather than considering load and wind distributions for the peak load hour. The reason for still considering LOLP in the peak load hour in this paper is simply out of practicality; yearly load distribution data were not available, nor were data for possible seasonal variations in available hydro capacity.

The paper concludes that wind power and grid expansion will have a positive effect on system adequacy. Wind power contributes to reducing the LOLP and can be attributed a capacity value. Similar results have been reported from various national studies, e.g. [1], [3], [6], [7], [8], [9] and [12]. The significance of this study is thus related to the real life case studied, being a region rather than a national system, and demonstrating the relevance of applying system adequacy studies for generation expansion and transmission planning of regional systems. The paper is innovative in considering the combined effect of wind farms and grid transmission capacity on LOLP, rather than just the effect of wind capacity alone. It shows that the smoothing effect due to geographical distribution of wind power contributes significantly to increasing the wind capacity value in systems with high penetration of wind energy. Compared to previous publication by the authors, [11], briefly summarized in [4], the case study is fully revised and considers grid expansion in combination with wind power. Further, the paper includes a sensitivity study on varying the assumed average wind power generation, the assumed availability and power curve of the wind turbines. The study finds that the results (LOLP and wind capacity value) are sensitive towards the assumed average wind power generation, but robust towards normal variations of the availability and power curve.

2. Calculation method

The system ability to meet the peak demand is basically a matter of available generation and transmission capacity. A rational measure on this is the loss of load probability (LOLP), i.e. the probability of the system meeting the peak demand. This can be calculated taking account for the installed generation and transmission capacity and the probability of these being in operation or having failed. Wind generation can be included in such calculations taking account for wind variations. International studies taking this approach show that wind generation contributes to reducing the LOLP level. Intuitively this can be understood as no generation or transmission is 100 % reliable – all have some probability of failing. Hence, even if wind generation may not be available at all times, this is also the case with all other system assets, and as such wind contributes to reducing the LOLP level in principle just as other generation.

The “capacity value” is a useful measure for comparing the impact of adding wind with adding other types of generation, say gas or hydro. The capacity value can be defined for any type of generation as the amount of 100 % reliable generation required for replacing the generation without changing the loss of load probability. Applying this definition, the capacity value of a 1000 MW thermal power plant is about 950 MW, [6], and for wind, at low to moderate penetration levels, the capacity value is equal to the average wind power produced during times of peak demand (typically about 30 % of installed wind power capacity, depending on the site conditions). At higher wind power penetration levels, the relative capacity credit becomes lower than the average wind power output at the peak demand hour [7].

Mathematically, LOLP can be expressed as:

$$LOLP = \Pr(P_m < 0) \tag{1}$$

where P_m is the generating capacity margin of the system. This work only consider LOLP calculations for the peak hour (maximum load) of the year, as opposed to e.g. [2] which divides the year into a specified number of time frames and calculates the LOLP for each time frame. Apart from this, the method used in this work is based on [2]. The impact of the wind generated power P_w is included by adjusting the consumers load P_l to the net load, i.e.:

$$P_n = P_l - P_w \tag{2}$$

and further by defining the generating capacity margin P_m as the difference between the available conventional capacity P_c and the net load P_n:

$$P_m = P_c - P_n \tag{3}$$

The probability Pr (P_m < 0) in (1) is calculated by using standard statistical methods as briefly described below.

The generating capacity margin distribution is calculated as the convolution of the available conventional capacity distribution and the net load distribution, i.e. no correlation between the available conventional generating capacity and the net load in the peak hour is assumed.

The net load distribution is calculated as the convolution of the wind power distribution and the consumers load distribution, i.e. no correlation between the wind power variations and the consumers load within the peak hour is assumed.

The wind power distribution from wind farm is calculated by the following two-step procedure:

- First the wind power distribution from one 100 % available wind turbine is calculated from time-series of the hour-to-hour wind speed variations and a typical wind turbine power curve. This approach makes it convenient to take into account the smoothing effect of geographically distributed wind power.
- Then the wind power distribution from the number of wind turbines in the wind farm is calculated as the convolution of the wind power distribution of the "ideal" wind turbine and the binomial distribution of the available wind turbines.

The grid expansion is included simply by considering possible grid import capacity to be represented in the model ala generators with a given (import) capacity and availability.

3. Representation of wind power in peak load hour

The wind generation is assumed as a base case split on three offshore wind farms some +100 km apart feeding into the regional grid. Applying one year of measured hourly wind speed from 2001 at these sites, and scaled to give 3000 full load hours (FLH) with the assumed wind farm power curve, a significant smoothing effect is observed, see Figure 1. It is observed that the probability of zero power output is almost 20 % for a single wind farm, while the corresponding value for the sum power output from three wind farms is less than 5 %. Thus, the smoothing effect will have a positive impact on the contribution of wind power to meet the maximum load. The smoothing effect is also evident for the periods with high wind speed; the three wind farms generates at full power at the same time less than 1 % of the year, compared to 10 % of the year for a single wind farm.

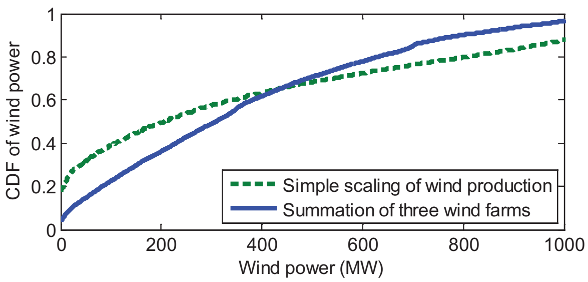


Figure 1: Cumulative distribution function of wind power.

An important assumption in this work is that the hourly measurements for the whole of year 2001 can be used to represent the wind speed in the maximum load hour. This is done due to the lack of available wind data for the maximum load hour. To give an indication of the validity of this assumption, daily wind speed data for one of the wind farm sites and temperature data from a reference station close to the load centre from 1961 to 2005 has been investigated. The daily wind speed values include the daily average value, the highest 10-minutes average and the lowest 10-minutes average. For every year, the average, maximum and minimum wind speed at the day with the lowest measured temperature at the reference sites has been collected, as it is assumed that the maximum load occurs at that day. This assumption is justified for the case study system using electricity for heating. The data is then compared with the average yearly wind speed for every day between 1961 and 2005 in order to see whether the wind speed at the maximum hour is typically lower or higher than the average wind speed over the year. The results are visualized in Figure 2, which shows that the wind speed at the day with minimum temperature typically fluctuates around the yearly average wind speed. This indicates that the expectation value of wind speed at the maximum load hour is close to the long-term average wind speed. The wind speed comparison is summarized in Table 1.

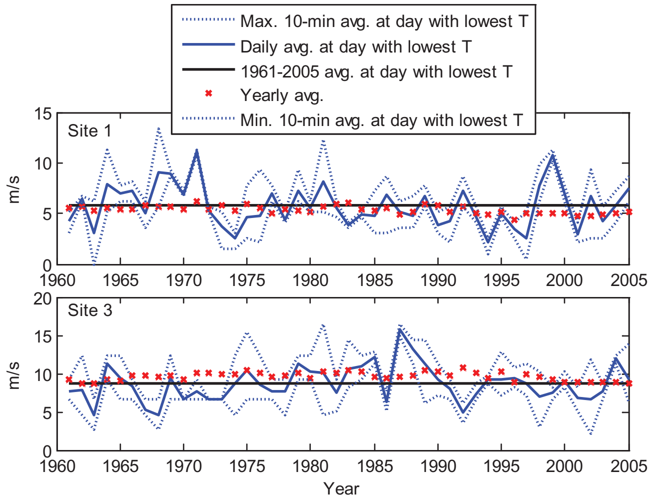


Figure 2: Comparison of yearly average wind speed (red crosses) with average wind speed at the day with minimum temperature (blue, solid line). The black horizontal line is the 1961-2005 average of the wind speed at the day with minimum temperature.

Table 1. Average value and standard deviation of daily wind speed data between 1961 and 2005.

Site 3 (1961-2005)	Avg. (m/s)	Std. (m/s)
u_{avg} for all days between 1961 and 2005	9.6	4.4
u_{avg} at day with lowest temperature	8.1	2.2
u_{max} at day with lowest temperature	10.7	2.8
u_{min} at day with lowest temperature	6.8	2.5

The average wind speed for all days between 1961 and 2005 in Table 3 slightly differs from the hourly average of 2001. This is as expected and simply reflects that the wind conditions vary from year to year. The main reason for using hourly observations from one whole year is that there is usually not enough historical data available for the peak hour, which in our case is assumed to occur at the day with lowest temperature. Using the wind data for the whole of 2001 to represent the possible wind conditions in the maximum load hour is an approximation, but judged to be fair as it compares well with the observed wind speed at low temperature days (1961-2005), see also Figure **3**.

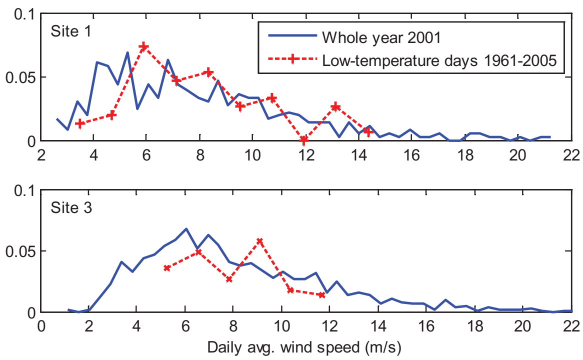
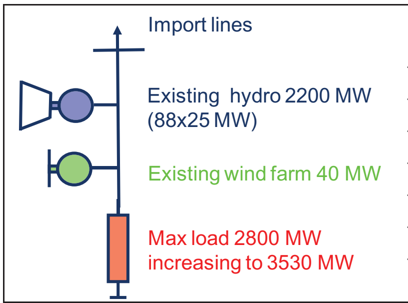


Figure 3: Distribution of observed daily wind speed at low temperature days (1961-2005) and distribution of daily wind speed in 2001, all scaled to an average of 8 m/s.

4. Case study specification

The case study uses data from a real life regional hydro-based power system. The system is running on a tight balance, and measures must be taken for meeting a future load increase. This is assessed assuming five alternatives, see Figure 4.



Case	Name	Load (MW)	Import (MW)	Wind (MW)	Gas (MW)	Hydro (MW)
A	BaseNow	2800	1700	41	0	2200
B	Grid	3530	1700	41	0	2200
C	Grid+Wind	3530	1700	1041	0	2200
D	Gas	3530	1270	39	360	2200
E	Gas+Wind	3530	1270	1041	360	2200
F	Wind	3530	1200	1041	0	2200
G	BaseFut	3530	1200	39	0	2200

Figure 4: Specification of case study system. “Import” is short for “Import capacity”.

The max load occurs in the winter period and is highly correlated with the outdoor temperature. This makes the max load a distribution rather than a fixed number. The assumed distribution of the maximum load is based on statistics from the Norwegian power system, and scaled to fit the regional case study system, see Figure 5. The distribution is calculated based on data from 26 years of temperature measurements.

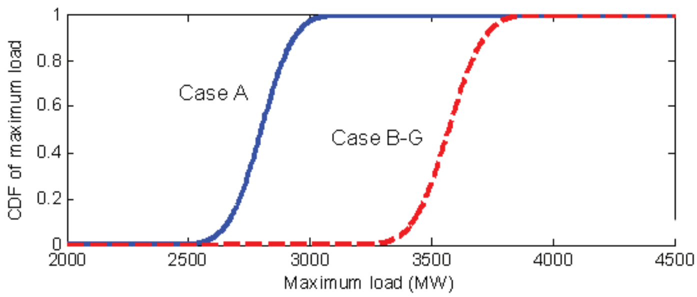


Figure 5: Cumulative distribution function (CDF) of the hourly maximum load.

Four import lines are assumed for case A and D to G, and five for case B (grid) and C (grid+wind). The import capacity is limited to be within N-1; a loss of one line shall not result in instability. The import capacity is thus not a fixed number, but depending on the load and generator mix as given in Figure 4. Thus, for the assumed case study system, the import capacity is actually decreasing from 1700 MW (case A) to 1200 MW (case G) for an increase in load because of voltage stability constraints. An extra line must be assumed to keep the import capacity at 1700 MW (case B and C). Adding a base-load gas turbine to the system is assumed to slightly assist, whereas adding wind is conservatively assumed not to influence the allowed import limit.

An implication of the assumed import limits is that the calculated LOLP in this study is not really for a loss of load, but for disconnecting interruptible loads as to maintain the system within N-1. If there still is a power deficit after disconnection of all interruptible loads, the N-1 criterion will be violated. This will only cause a loss of load situation if at the same time one of the import connections becomes unavailable, which is very unlikely, i.e. the actual LOLP for prioritised loads will be lower than calculated here. Thus, the term "Loss of load probability" in this study shall be understood as the probability of disconnecting interruptible loads and/or violating the N-1 criterion.

The assumed wind and gas capacities are selected to be directly comparable; both options will provide for 3 TWh annual generation assuming 3000 full load hours (FLH) for the wind farms and 8300 FLH for the gas turbine.

For calculation of the loss of load probability and capacity value, the unit sizes and availability factors shown in Table 2 are used.

Table 1: Unit sizes and availability factors

	Wind	Gas	Hydro	Lines
Unit size (MW)	3	360	25	425 - 300
Availability (%)	98	98	99.8	99.6

The availability factor assumed for wind (98 %) is likely optimistic for offshore wind farms, but the assumption will be shown to have no significant effect on the resulting LOLP or capacity value.

The availability factor for the gas turbine (98 %), hydro generators (99.8 %) and lines (99.6 %) are according to detailed failure statistics. Internal grid constraints within the study region are not considered.

The unit sizes of the lines are set between 425 and 300 MW according to the assumed number of lines and combined import capacity; Case A: 4x425, B/C: 5x340, D/E: 4x317,5 and F/G: 4x300 MW.

5. Results

5.1. Main results

The main results are displayed in Table 3. The symbols in the table are:

- LOLP : Loss of (interruptible) load probability
- ECM : Expected capacity margin
- EDNS : Expected (interruptible) demand not supplied
- CVwind : Capacity value of wind power in percent of installed capacity

Table 2. Calculated results of case study.

Case	Name	LOLP (%)	ECM (MW)	EDNS (MW)	CVwind (%)
A	Base2002	≈ 0	1078	≈ 0	31
B	Grid	1.7	308	1.5	32
C	Grid+Wind	0.4	651	0.3	14
D	Gas	4.7	233	4.8	33
E	Gas+Wind	1.2	577	1.2	16
F	Wind	39.7	154	58.7	23
G	Base2012	95.0	-190	192.3	37

The loss of load probability in case A is practically zero with the assumptions made here. This is as expected considering the high capacity margin. However, if no new capacity is installed and the load increases as projected (Case G), the LOLP increases to 95 %.

By constructing a new line (Case B), the LOLP-level becomes 1.7 %. This is likely a satisfactory level. Adding wind to this (Case C), the LOLP-level is reduced to 0.4 %, and the capacity margin is raised from 308 MW to 651 MW. By installing 1000 MW wind power without any new import possibilities, the LOLP-level is reduced from 95 % (Case G) to 39.7 % (Case F). This shows that wind power contributes significantly to the supply reliability of the region, though is not sufficient on its own for this case study system.

Case D (360 MW gas power plant) gives a LOLP-level of 4.7 %. Case E (wind and gas) gives a LOLP-level of 1.2 %, i.e. satisfactory as an alternative to grid reinforcements only (Case B).

Figure 6 and Figure 7 show the cumulative distribution of the net load and the capacity margin, respectively. It is seen that the wind power variations results in a higher variability of both the net load and the capacity margin (the CDF's becomes less steep). By comparing e.g. Case B (grid) and Case C (grid + wind) in Figure 7, it is evident that wind power improves the generating capacity margin significantly.

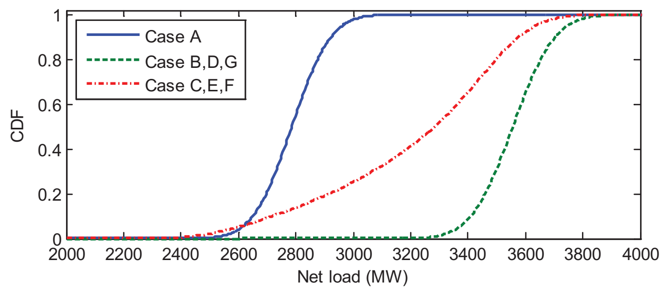


Figure 6: Cumulative distribution function (CDF) of the net load (maximum load – wind generation).

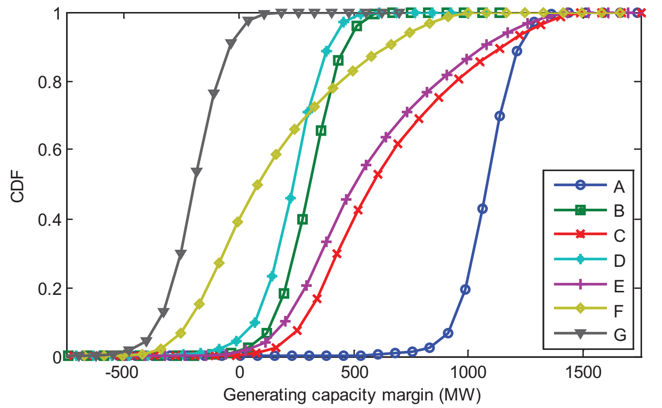


Figure 7: Cumulative distribution function (CDF) of the generating capacity margin for all cases.

In Figure 8, the capacity value of wind power is plotted as a function of installed wind power from 20 MW to 1000 MW. Figure 8 a) shows that 500 MW of wind power is equivalent to approximately 104 MW of 100% reliable conventional generation capacity. With 100 % increase in wind capacity (from 500 MW to 1000 MW), the capacity value increases by 37 % (from 104 MW to 142 MW). This means that the relative contribution of wind power to supply the maximum load decreases as more wind power is installed.

The difference between the results for three sites (blue line) and one site (red line) shows that the geographical smoothing effect is very important when evaluating the contribution from wind power to the supply reliability.

Figure 8 b) and c) shows the capacity value in percentage of installed wind power. At low penetration levels, the capacity value is close to the average wind power output and there are no differences between three sites and one site. The smoothing effect becomes more important as the penetration level increases. Please note that the penetration level in Figure 8 c) is defined as the wind energy penetration, not wind capacity penetration. In this case study, 14 % wind energy penetration, corresponds to 30 % wind capacity penetration, i.e. wind capacity in percentage of the total capacity in the region (hydro + wind).

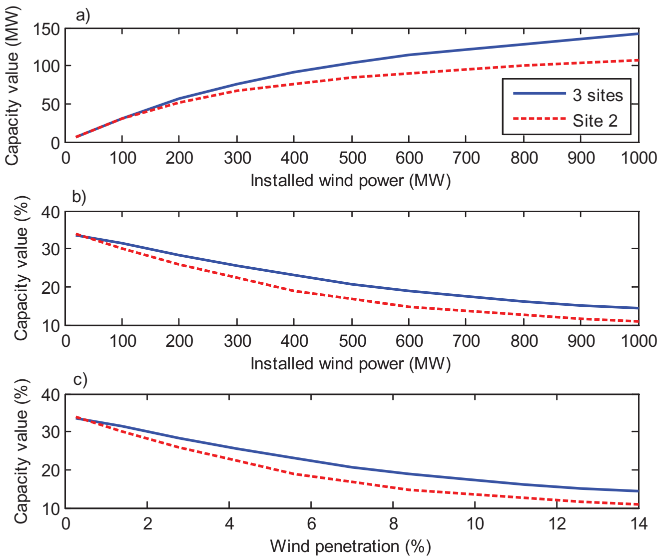


Figure 8: Capacity value of wind power with and without geographical smoothing effect. a) Capacity value in MW. b) Capacity value in percentage of installed wind power. c) Capacity value as a function of wind energy penetration level.

5.2. Impact of varying model parameters

In this section, three important model parameters are adjusted to evaluate how the uncertainties in the assumptions made here influences the results. The evaluated model parameters are:

- The chosen wind power curve.
- The assumed average wind power generation in the max load hour.

- The availability factor of wind turbines and the combined-cycle gas turbine.

The chosen wind power curve is based on the Enercon E70 with storm control. The storm control function reduces gradually the power output as the wind speed increases beyond the cut-out wind speed. Similarly, the power output is gradually increased from zero to rated power when the wind speed becomes lower again. Normally, a wind turbine reduces the power output quickly to zero at the cut-out wind speed, and goes back to production when the wind speed reaches a threshold value lower than the cut-out wind speed. This hysteresis effect is not possible to include since the calculations are based on a probabilistic method instead of a chronological simulation model. Another aspect is that the total power output of a wind farm does not follow exactly the shape of the design power curve for one turbine.

Finally, with as much as 1000 MW wind power, there might be significant differences between the wind turbines chosen for the different wind farms. To evaluate these uncertainties, the capacity value from using the original power curve is compared with a power curve based on Nordex v80 with two different cut-out wind speeds. The results are calculated for Case C (grid + wind). The differences in power curves give only small discrepancies in the results; see Table 4.

Table 3: Calculated wind capacity value for assuming different power curves.

	CVwind (MW)	CVwind (%)
Enercon E70, storm control	150	14.4
Nordex V80, vcut-out = 25 m/s	145	13.9
Nordex V80, vcut-out = 20 m/s	143	13.8

An aspect that is expected to have a strong impact on the supply reliability is the assumed average wind generation in the max load hour. This is assessed for Case E (wind + gas) assuming variations in the average wind generation (expressed by number of full load hours). Figure 9 shows the results on LOLP and wind capacity value. A 10 % increase in the average wind generation gives a reduction in LOLP of 13 % and an increase in capacity value of 8 %.

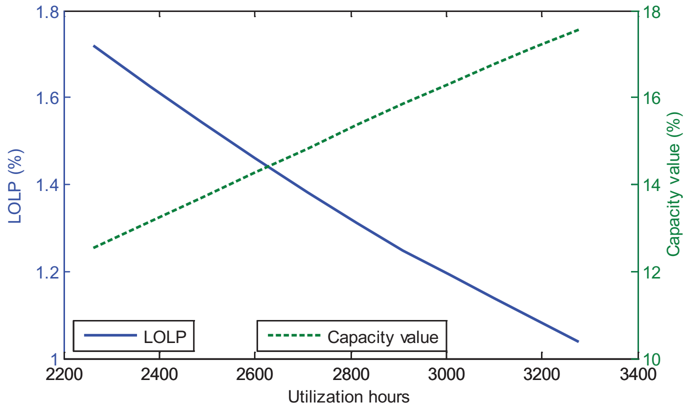


Figure 9: Loss of load probability and capacity value as a function of the number of full load hours (utilization hours) of total wind generation at the maximum load hour. The results are for Case E.

The availability factor of the wind farms will vary depending on the site conditions and choice of turbines. However, probable variations in the availability of individual wind turbines will have no practical effect on the LOLP because of the vast amount of turbines that comprises the total wind power installation in the region, see Figure 10. The gas power plant, on the other hand, consists of only one unit, and thus the LOLP will be strongly dependent on the availability factor. Availability factors of offshore wind farm transformer stations and export cables have not been accounted for in the case study. To assess the impact of these components, an additional LOLP calculation of the same case as presented in Figure 10 (Case E) has been carried out. In this the offshore wind power is represented as three large units each 347 MW, and each with an availability factor of 0.9. This gives a LOLP of 1.3 %, i.e. quite close to 1.2 % as was found for the original case using 3 MW units with 0.98 % availability.

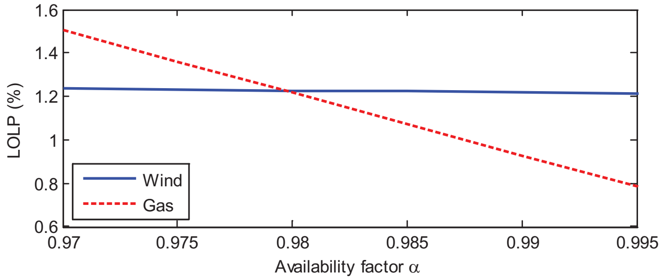


Figure 10: Loss of load probability as a function of the wind power and gas power availability factors. The results are from Case E (wind+gas).

6. Conclusions

The impact of offshore wind power on system adequacy has been studied applying anonymous data from a real life regional hydro-based power system. It is found that the wind generation contributes to the system adequacy by reducing the Loss of Load Probability (LOLP) and can be attributed a capacity value. At low wind energy penetration, the wind capacity value will be about 33 % of the installed capacity, i.e. close to the average power output at the hour of peak demand, and decreasing in relative terms for increasing wind energy penetration. For 1000 MW wind capacity (14 % penetration level), the capacity value is about 15 %. An important result is that the smoothing effect due to geographical distribution of wind power has a significant impact on the wind capacity value at high penetration. Three geographically distributed wind farms give a higher contribution to reducing LOLP than one large concentrated wind farm. Generalizing this suggests that geographically distributed offshore wind farms in a future system linked in a strong transnational (or trans-region) grid can be attributed a higher capacity value than that of a single concentrated wind farm.

The sensitivity study carried out finds that wind turbine manufacturer specific differences in power curves give very small discrepancies in the results. The same goes for variations in the assumed availability factor for the wind turbines. The results are however sensitive towards variations in the assumed average wind generation in the max load hour. A 10 % increase in the average wind generation gives a reduction in LOLP of 13 % and an increase in wind capacity value of 8 %.

Comparing expansion with wind farms and base-load gas power, both specified to give the same annual generation, the capacity value of wind is lower than for the gas power plant for the case of high wind energy penetration. At low wind energy penetration however, the capacity value of wind and base-load gas generation would both be close to their average generation.

The paper is innovative in considering the combined effect of wind farms and grid transmission capacity on LOLP, rather than just the effect of wind capacity alone. The demonstrated methodology can be generally applied in system adequacy studies for generation expansion and transmission planning. This is of high relevance for developing the power systems of the future with large offshore wind farms and strong transnational grids.

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