

Capacity Value of Wind Power

Task Force on the Capacity Value of Wind Power, IEEE Power and Energy Society

Andrew Keane, *Member, IEEE*, Michael Milligan (*Vice-Chairman*), *Member, IEEE*, Chris Dent *Member, IEEE*, Bernhard Hasche, Claudine D'Annunzio, *Student Member, IEEE*, Ken Dragoon, Hannele Holttinen, Nader Samaan, *Member, IEEE*, Lennart Söder, *Member, IEEE*, and Mark O'Malley (*Chairman*), *Fellow, IEEE*

Abstract-- Power systems are planned such that they have adequate generation capacity to meet the load, according to a defined reliability target. The increase in the penetration of wind generation in recent years has led to a number of challenges for the planning and operation of power systems. A key metric for generation system adequacy is the capacity value of generation. The capacity value of a generator is the contribution that a given generator makes to generation system adequacy. The variable and stochastic nature of wind sets it apart from conventional energy sources. As a result, the modeling of wind generation in the same manner as conventional generation for capacity value calculations is inappropriate. In this paper a preferred method for calculation of the capacity value of wind is described and a discussion of the pertinent issues surrounding it is given. Approximate methods for the calculation are also described with their limitations highlighted. The outcome of recent wind capacity value analyses in Europe and North America, along with some new analysis are highlighted with a discussion of relevant issues also given.

Index Terms-- Wind power, capacity value, effective load carrying capability, power system operation and planning

I. INTRODUCTION

POWER system reliability is divided into two basic aspects, system security and system adequacy. A system is secure if it can withstand a loss (or potentially multiple losses) of key power supply components such as generators or transmission links. Generation system adequacy refers to the issue of whether there is sufficient installed capacity to meet the electric load [1]. This adequacy is achieved with a combination of different generators that may have significantly different characteristics. Capacity value can be defined as the amount of additional load that can be served due to the addition of the generator, while maintaining the existing levels of reliability. It is central to determining a system's generation adequacy. It is used by system engineers to assess the risk of a generation capacity deficit [2].

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A. Keane and M. O'Malley are with University College Dublin, Ireland (e-mail: andrew.keane@ucd.ie, mark.omalley@ucd.ie).

In recent years it has gained importance, in light of the increased uncertainty arising from wind power availability, which is a function of the local weather conditions.

The metrics that are used for adequacy evaluation include the loss of load expectation (LOLE) and the loss of load probability (LOLP). LOLP is the probability that the load will exceed the available generation at a given time. This criterion only gives an indication of generation capacity shortfall and

lacks information on the importance and duration of the outage. LOLE is the expected number of hours or days, during which the load will not be met over a defined time period. The effective load carrying capability (ELCC) is the metric used in this paper to denote the capacity value [3].

The topic of capacity value of wind power has been attracting attention in recent times with a number of publications dealing with this issue. In [4] methods for capacity value are described, and classified as either chronological or probabilistic. A range of methods for the calculation of capacity value are assessed in [5, 6]. A generalised version of [3] is presented in [7] with the key innovation being a multi state representation of wind power. A new approximate method for the adequacy assessment called the Z method is given in [8]. The utilization of an autoregressive moving average model of wind power along with sequential Monte Carlo simulation is presented in [9-12]. In [13] a well being analysis framework is used to combine deterministic and probabilistic approaches to determining system adequacy. Currently a wide range of approaches have been implemented in academia and industry, each with their own inherent limitations and approximations. This paper is the result of work undertaken by the Taskforce on Capacity Value of Wind, which was proposed by the Wind Power Coordination Committee and Power Systems Analysis, Computing and Economics committee of the IEEE Power and Energy Society (PES). The overall objective of the taskforce has been to provide clarity on the calculation of capacity value of wind. This paper is the outcome of the taskforce meeting and panel session which took place at the IEEE PES General Meeting in Pittsburgh, 2008.

The paper classifies the current approaches used for the assessment of the capacity value of wind power generation. In particular, a preferred method is recommended and described in detail in Section II. Other approximate methods are described in Section III, with the limitations of each highlighted and recommendations made as to their usage. The results of relevant international studies are described in Section IV. A discussion of relevant issues is given in Section

V, with conclusions and recommendations given in Section VI.

II. PREFERRED METHODOLOGY

A. Method Description

This method is based directly on the definition of capacity value given above. Conventional thermal generation is still the most common form of generation in power systems. They are modeled by their respective capacities and forced outage rates (FOR). Each generator capacity and FOR is convolved via an iterative method to produce the analytical reliability model (capacity outage probability table (COPT)) of the power system. The COPT is a table of capacity levels and their associated probabilities [1]. The cumulative probabilities give the LOLP for each possible available generation state. Wind power cannot be adequately modeled by its capacity and FOR as wind availability is more a matter of resource availability than mechanical availability. This leads to a different treatment of wind generation in the traditional ELCC calculation method, which is now summarized in the following three steps:

1. The COPT of the power system is used in conjunction with the hourly load time series to compute the hourly LOLPs without the presence of the wind plant. The annual LOLE is then calculated. The LOLE should meet the predetermined reliability target for that period. If it does not match, the loads can be adjusted, if desired, so that the target reliability level is achieved.
2. The time series for the wind plant power output is treated as negative load and is combined with the load time series, resulting in a load time series net of wind power. In the same manner as step 1, the LOLE is calculated. It will now be lower (and therefore better) than the target LOLE in the first step.
3. The load data is then increased by a constant ΔL across all hours using an iterative process, and the LOLE recalculated at each step until the target LOLE is reached. The increase in peak load (sum of ΔL s) that achieves the reliability target is the ELCC or capacity value of the wind plant.

B. Factors Influencing Capacity Value Calculation

For thermal units, the primary characteristics that influence the overall system adequacy are the units' available capacity and FORs. Long-term FORs are typically available by type and size of unit, compiled from a large data set of similar units. Modelling wind power using 2-state distributions in this manner is not recommended as wind is a highly variable resource which cannot be adequately modeled by a two state model.

With respect to wind power, the relationship between the wind and the load is a key factor to be captured by the calculation method. The correlation between wind and load is site dependent. In some areas there is a diurnal and/or seasonal wind pattern. Although the hourly correlation between wind

and load can be nearly zero, there may be a considerable correlation among wind and load data when binned according to rank. A physical mechanism for this may be that load extremes are often due to relatively infrequent large-scale high-pressure weather systems that typically bring calm winds. This implies the existence of systematic patterns of wind generation during system peaks and other time periods that cannot be ignored. As an example, data used in the Minnesota 20% Wind Integration Study [14] was used to calculate correlation coefficients by deciles (10 equal divisions) and vigicles (20 equal divisions). Deciles are data that is sorted into ten equal parts. Vigicles refer to the same concept where twenty equal parts are employed. The results are shown in Fig. 1. The figure shows the relative ranking of wind and loads by dividing them into deciles and vigicles and is based on the average wind or load within the grouping. The annual correlation coefficient of the hourly wind and load data is relatively small at -0.158. However, after computing the midpoints of each decile and basing the calculation on those, the correlation coefficient is considerable at -0.908, and the corresponding vigicle correlation coefficient is -0.889. Therefore, it is critical to use hourly wind and load data from the same year so that the underlying relationship between wind and load is implicitly captured in the modeling. The linear correlation coefficients provide limited information about the relationship between two variables, but are used here as part of a simplified illustration.

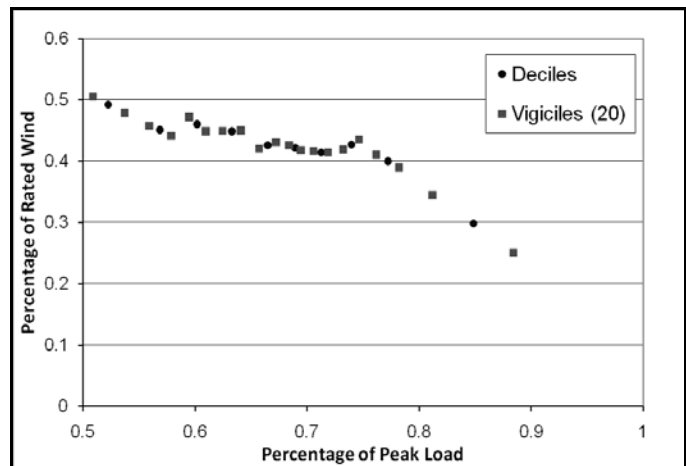


Fig. 1. Correlation between wind and load based on deciles and vigicles

Although the key driver of wind capacity value comes from the general correlation of wind and load, it is important to remember that ELCC is a function of many different system parameters. Some of these include hydro generation schedules (generally highly correlated with load), import-export schedules (often high imports are correlated with load), and maintenance schedules for conventional units. This latter impact can occur if maintenance outages have a significant impact on LOLP during shoulder seasons, and if there is significant wind generation during those times [15]. The geographic dispersion of both wind and load will also impact ELCC, as will the wind penetration level.

Fig. 2 illustrates the effect of an additional generator on the reliability curve, where it is seen to move to the right. ELCC is

the contribution to overall adequacy, represented by the movement of this curve. The case illustrated uses the common LOLE target of 1 day/10 years. This target, although commonly used, can be changed to reflect the acceptable risk level of the region. The selected target reliability level can have a large impact on the capacity value of both conventional power and wind power [5]. When the target reliability level, is lower, and LOLP higher, there is relatively more value in any added capacity than in cases where LOLP is very low [15]. LOLE targets and calculations can be expressed in days per year or hours per year. The relationship between hours per year and days per year is not a factor of 24 and depends on the generating system and load parameters. It is important to note that there is a distinction between these calculation methods that use daily LOLE values and hourly LOLE respectively. The calculation of a daily LOLE based on peak load values will be more pessimistic and is distinct from an hourly LOLE calculation. Both daily and hourly LOLE are valid metrics, but clarity regarding their application should be ensured.

A common approach is to estimate LOLE and related indices for one balancing area of the whole interconnection, e.g. for a utility, a state or a country. The interpretation of LOLE is then not “Loss of Load Expectation”, but instead expectation of requirement to import.

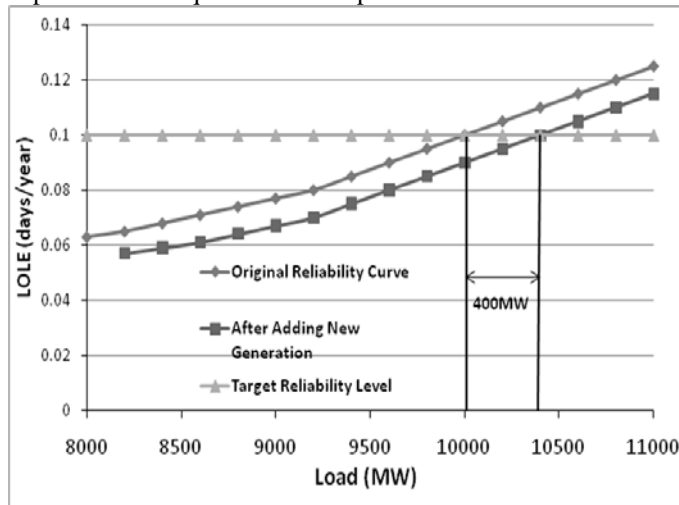


Fig. 2 Effect of generator addition on LOLE

In many systems where the calculations show a given expectation of capacity deficit, the true expectation of capacity deficit is much lower because there is a non-zero probability of available imports which are not otherwise accounted for in the analysis. The impact of imports could be modeled within the preferred method if the data is available for the interconnections into the system. For comparison of capacity values between systems, the system is initially modified to give a standard LOLE value such as 1 day in 10 years; this then allows comparison of the capacity value of wind between systems. This does not give a true measure of the adequacy of the systems where LOLE values are different, but allows for wind's contribution to be assessed and compared against other systems that used this standard value, as well as compared against other energy sources.

The input data employed is a key factor in the calculation of capacity value. It should be noted that regardless of the method

employed, if sufficient data of the required quality is not available, the resulting answer cannot be relied upon. The preferred method requires:

- 1) Load time series for the period of investigation (multi-year of at least hourly resolution is preferable)
- 2) Wind power time series for the same period as the loads
- 3) A complete inventory of conventional generation units' capacity, forced outage rates and maintenance schedules

The length of the period of investigation required is an open question with wind power. For wind and other variable generators, it has been common practice to use one or more years of hourly generation data to calculate wind's ELCC. This approach, although a reasonable start, does not adequately represent the long-term performance characteristics of wind power plants in the same way that long-term representations are made for conventional units. Multiple years of time series data are preferred as there can be a significant inter-annual variation of the wind resource [16]. If the wind time series is only for a single year, then the calculated LOLE will be simply a historical assessment rather than a predictive one. The number required to provide a robust answer is dependent on a number of factors including the size of the system, load curve and penetration of wind power on the system. The overall output for each year is important, but the timing of the wind output is also a very important factor to be captured. This reemphasizes the need for time synchronized data with the load.

An important characteristic of wind power is its spatial diversity. With respect to capacity value, weaker geographical relationships are advantageous, as this results in a higher capacity value of the whole wind fleet, due to the smaller probability of very low output across the whole system. This also means that the capacity value increases relatively with larger region sizes. If in contrast the generation profiles are perfectly correlated, the installation of additional capacity does not compensate for the low wind hours; in this case, while additional installed capacity would increase the MW capacity value, the capacity value as a percentage of rated capacity would decrease.

Wind data of the required quality and quantity has been scarce to date due to many wind plants only being recently installed. In addition, this time series data can be commercially sensitive, making it harder to obtain. For other energy resources such as hydro power, this is less of a problem as it is a well established, mature technology with decades of good quality data often being available. As noted above, calculation of the “true” multi-area LOLE and related indices should consider possibilities of import. This means that representative time series for import levels and their respective likelihoods in neighboring systems should be used.

Synthetic time series have been proposed in the literature as a means of reconciling the sometimes limited availability of historical wind time series [9-12]. 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.

III. APPROXIMATE METHODOLOGIES

This section outlines some of the approximate methodologies that have been employed for calculation of capacity value. They are included as a means of contrast with the preferred method and also to highlight the approximations and assumptions they make. The preferred method contains approximations also but as it utilizes the datasets which explicitly capture the full relationship between load and wind it does provide the best assessment of wind's capacity value.

It is important to note that with modern computing power the preferred method is not overly time-consuming for moderately sized systems; indeed, a multi-year calculation can be run in a matter of seconds on a desktop PC. Approximation methods must therefore be justified on grounds of ease of coding, lack of data, or on grounds of greater transparency which aids the interpretation of results.

A. Garver approximation based methods

Garver proposed a simplified, approximate graphical approach to calculating the ELCC of an additional generator [3]. This has been an important method in the calculation of capacity values but has been superseded by advances in computing power. Although the paper's focus was on the graphical approach, the same underlying methodology can be used to estimate the ELCC of a wind generator added to a given power system. Garver's approximation and its extension to multi-state units [6] are based on two main assumptions:

- The multi-state unit representation of wind described below is used; the probability distribution for wind availability is the same at all times.
- The LOLE before addition of the wind may be approximated as Be^{md_0} , where d_0 is the peak demand, and m and B are fitting parameters.

The ELCC (\bar{d}) of the wind generation is then calculated as

$$\bar{d} = -\frac{1}{m} \ln \left[\sum_i p_i e^{-mw_i} \right] \quad (1)$$

where p_i is the probability that the available wind capacity is w_i .

B. Multi-state unit representation

An alternative risk calculation to the preferred method is the multi-state approach, which utilises a probabilistic representation of the wind plant [7, 17, 18]. Similarly to conventional units with de-rated states, the wind plant is modeled with partial capacity outage states each of which has an associated probability. To evaluate the LOLP at a given time, the wind generation is included in a COPT calculation in the same manner as a multi-state conventional unit. The ELCC calculation then proceeds as described in the preferred method, except using the modified calculation. A multistate approach is adopted in [19] where a Markov model is employed to model wind in discrete states.

The multi-state model for wind power is typically constructed from a histogram of the wind power output for the chosen period. A major concern associated with this approach is the loss of information on wind/load correlation. In most regions there is significant seasonal and diurnal variation in wind energy availability, as well as effects of weather on demand; these cannot be adequately described by a single probability density function for all periods. This concern may be addressed to some extent by using different probability distributions for different categories of hours. The total LOLE would then be evaluated by adding the LOLEs from the various categories of hour. However, such a modification still does not fully account for the correlation between demand and wind availability. Such effects will be captured automatically when the preferred methodology is employed.

C. Annual peak calculations

Loss of load probability at time of annual peak demand is used as a proxy for system risk in some regions, for example Great Britain has generally followed this practice [20, 21]. The definition of ELCC for peak calculations remains the same as for year-round risk calculations, except that the risk index used is LOLP at time of annual peak. It follows that probability distributions are required for the demand and available wind capacity at time of annual peak (the distribution for available conventional capacity is derived via a COPT calculation, as in the preferred ELCC calculation method.)

The requirement for a probability distribution for available wind capacity is problematic, because peak demand by definition occurs once a year, and hence by definition the available data is very limited. Two approaches which have been used in investigating the wind resource at annual peak are:

- 1) Use a histogram of hourly load factors for the entire peaking season. This has the disadvantage that many days are not close to annual peak demand, so their relevance is limited if the wind/demand correlation is substantial.
- 2) Use a histogram of load factors from hours where demand is within a certain percentage of that year's peak. This ensures greater relevance to peak demand, at the expense of reducing the amount of data used.

The main criticisms of an annual peak calculation are that it does not explicitly consider loss of load at other times of the year, and that it is difficult to obtain appropriate probability distributions for the wind resource at annual peak, and also for the peak load.

D. Peak-period capacity factors

There has been considerable interest in using capacity factors (average output) calculated over suitable peak periods to estimate the capacity value of wind. Some of these approximations are reasonably accurate [5]. In [22] a good approximation was achieved only if hydro and import-export transactions were ignored. As discussed previously, this is no surprise because hydro and transaction schedules are often positively correlated with load. Although capacity factor

approximations may be useful as quick screening methods (for instance, a higher capacity factor would usually imply a higher capacity value on the same system), we do not endorse them here as they do not capture the short term or annual variability of wind power, or the correlation of wind availability with demand.

E. Z Statistic Method

The z-statistic method [8] is based on taking the difference between available resources and load over peak demand hours (surplus availability) as a random variable with an associated probability distribution. The z-statistic for that distribution (mean divided by standard deviation) is taken as the primary system adequacy metric. The incremental load carrying capability for an added power plant is taken to be the load addition that keeps the z-statistic constant. For small changes in the overall system, keeping the z-statistic constant is equivalent to maintaining a constant LOLP. This approach is therefore an approximate method for annual peak ELCC calculation. The following assumptions are involved in its formulation:

- The shape of the probability distribution for the margin of available capacity over demand does not change significantly on adding the wind (though the mean and standard deviation (SD) may change).
- The SD ($\bar{\sigma}$) of the distribution for available wind capacity is small compared to the SD of the distribution for available capacity from the existing generation. As a consequence, the z-method approximation is only valid for low wind penetrations.

These allow a transparent closed-form expression for ELCC to be derived. The method is most conveniently stated by regarding the z-statistic for margin as a proxy for LOLP. The ELCC (\bar{d}) is then the load addition that keeps the z-statistic constant:

$$\bar{d} = \bar{\mu} - \frac{z_0 \bar{\sigma}^2}{2\sigma} \quad (2)$$

where $\bar{\mu}$ is the mean wind load factor over peak load hours, and z_0 is the z-statistic representing the LOLP level. Due to it being a perturbation method, and due to the assumption that the shape of the distribution for available margin is unchanged, it is especially accurate for small incremental wind penetrations, and progressively less accurate for evaluating large increments of wind generation on a power system.

This method's principal advantage lies in the transparency of the formula for ELCC; it provides greater insight into what influences the level of ELCC than iterative calculations. The usefulness of the method is in providing a relatively simple rapid method for determining how wind variability and correlations among wind projects affect the load carrying capability.

IV. CASE STUDIES

This section presents summary results from capacity value studies around the world. In each of the studies different methods have been applied which partly explains why there

are differing capacity value levels. There are also differences between the results of the studies due to the differing characteristics of the wind and demand profiles in each of the regions under study.

A. Comparison between Preferred and Approximate Methods

This section details a comparison of capacity value results obtained from studies on the Great Britain and Ireland systems, utilizing wind power and plant portfolio data from each system [23].

This study demonstrates clearly that the benefits of the preferred LOLE-based approach include automatically accounting for the wind-demand relationship and geographical diversity in the resource, and giving a broader picture of risk beyond the time of annual peak. An annual peak LOLP calculation requires a probability distribution to be derived for the available wind capacity at time of annual peak. By definition there are few hours of direct relevance; indeed, as extreme demands tend to be driven in most power systems by extreme weather, it might be expected that the error will be induced if an annual peak distribution is based on either all periods with demand within a certain percentage of peak, or all daily peaks in the peak season.

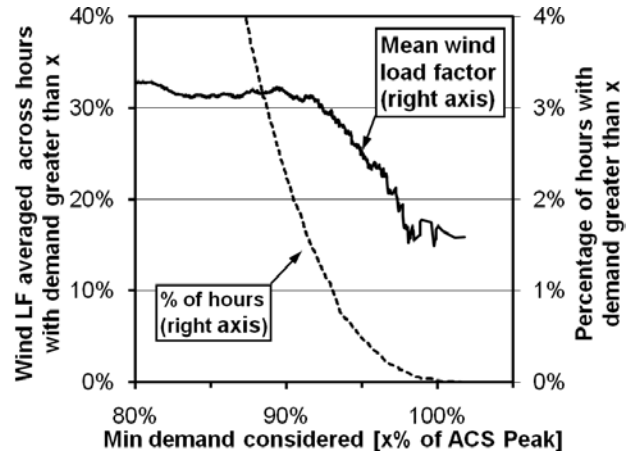


Fig. 3: Relationship between available wind load factor from the transmission-connected wind farms in GB and system-wide demand. Data from the two winters 2007-8 are plotted. (ACS is Average Cold Spell)

Fig. 3 illustrates the critical importance of accounting correctly for the relationship between wind availability and demand. It shows clearly that over the winters 2007 - 2008, the mean wind load factor across the hours of very highest demand was considerably lower than the mean load factor across more typical (lower) winter demands. This confirms that any group of hours spread across the whole winter, without consideration of demand level, will not be representative of absolute peak demand; plotting the mean load factor across all hours above a certain demand (as in Fig. 3) combines the degree of aggregation which is needed to reveal any trend, with the necessary focus on the hours of highest demand.

The capacity credit results from the Great Britain and Ireland systems use the preferred LOLE-based approach. The probability distribution for available conventional generating capacity is derived through a capacity outage probability table method as described in Section II. Metered wind and demand data from the years 2007 and 2008 (for which coincident time

series were available for both systems) is used. Before adding the wind generation, the GB peak demand and LOLE are 60 GW and 0.061 hour/year; the figures for Ireland are 5.05 GW and 1.87 h/y. These figures illustrate the relative differences in generation adequacy between a large and small system and should not be taken as definitive figures for the adequacy of these systems.

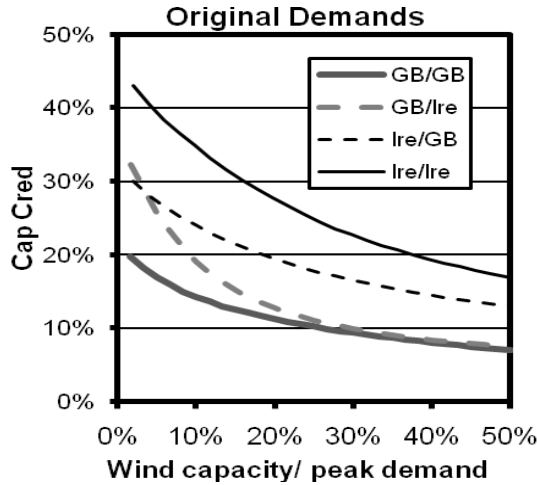


Fig. 4: Capacity credit results from the GB and Irish systems. Sys1/Sys2 denotes demand and conventional generation from Sys1/wind data from Sys2.

Capacity credit results are shown in Fig. 4 for the original demands. The Irish wind data gives higher capacity credit results than the GB data, as the Irish wind load factors are on average higher. Also, in common with other studies, the capacity credit as a percentage of installed wind capacity decreases with increasing wind capacity (because at higher wind capacities the possibility of very low output becomes more important on a system scale), and the capacity credit result increases as demand is increased (as any generation is more valuable to the system when risk is higher).

More surprising is the result that the Irish system consistently gives higher capacity credit values than GB for the same wind data. This is explained by the fact that in the smaller Irish system the variations in available conventional capacity are larger relative to installed capacity or peak demand. As a result, when the same percentage wind penetration is added to the two systems, the distribution for available capacity broadens less in the Irish system than in GB; hence, in this calculation the wind capacity appears 'firmer' in Ireland than in GB, and the calculated capacity credit is then higher.

Fig. 5 shows a comparison between the preferred method and two approximate methods, (Garver and Peak). It can be seen that when load levels below 90% are not considered the ELCC is generally overestimated. When only very high load levels are considered (>97%) the ELCC is lowest, corresponding with Fig. 3 which shows that in Great Britain the wind load factor drops off considerably at these demand levels [24].

Fig. 6 shows a comparison between the preferred COPT method, the Z method and the COPT method where a normal distribution is assumed for conventional plant. The Central Limit Theorem implies that the sum of a large number of independent random variables will be approximately Normally

distributed, as long as no one variable dominates the sum. If the wind capacity is small enough, these conditions remain satisfied for the available capacity distribution even after the wind is added (a Normal approximation for the wind distribution itself is not required).

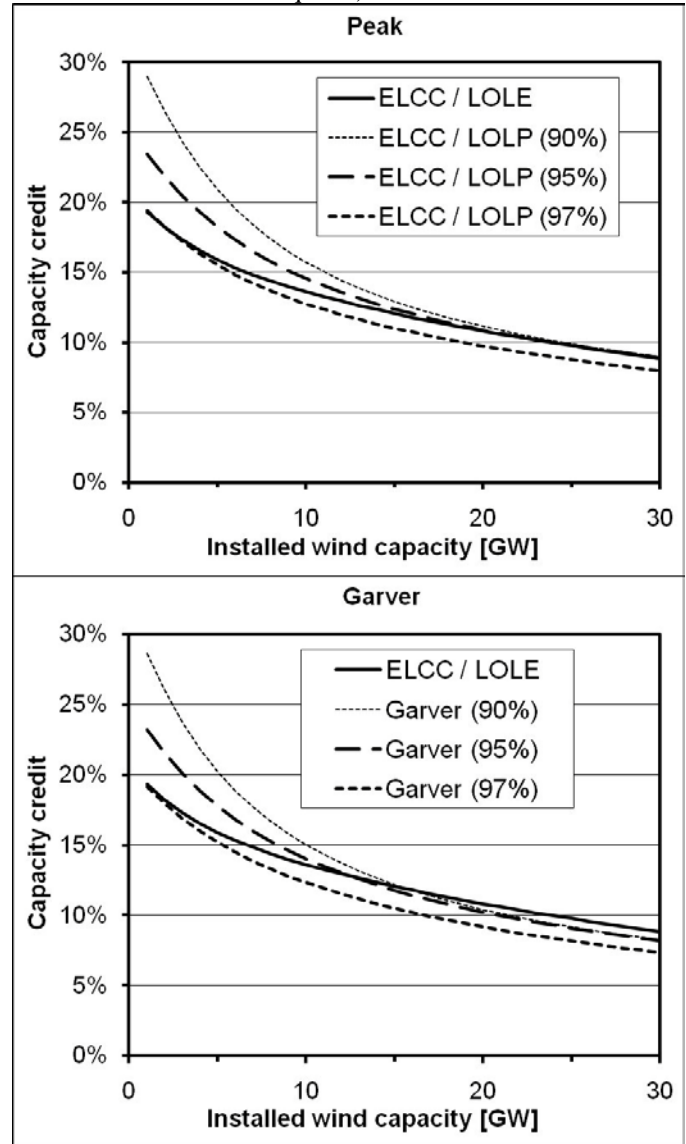


Fig. 5. ELCC as determined using peak and garver approximations compared to preferred method [24]

Therefore, following the addition of a small wind capacity, the Normal approximation for the total capacity inherent in the Z method remains reasonable. The observations in the previous paragraph suggest that (for this example at least) the assumption that the shape of the available capacity distribution does not change on adding the wind is equivalent to the stronger assumption of a Normal distribution.

Fig. 7 shows the application of the preferred method to the Irish system exposed to different years of wind data. It shows the considerable variation, (up to 35%), that can occur between years depending on the overall wind resource in those years and the timing of the wind output [25].

B. New York State Study

The objective of this study was to assess the effective load carrying capability of future wind resources in the State of New York [26]. The preferred method in Section II was used with the addition of considering the power transfer limits of the tie lines between different control areas. The historical NYISO hourly load data for 2001, 2002 and 2003 at different buses were used. The peak demand for the period of investigation was 30,982 MW.

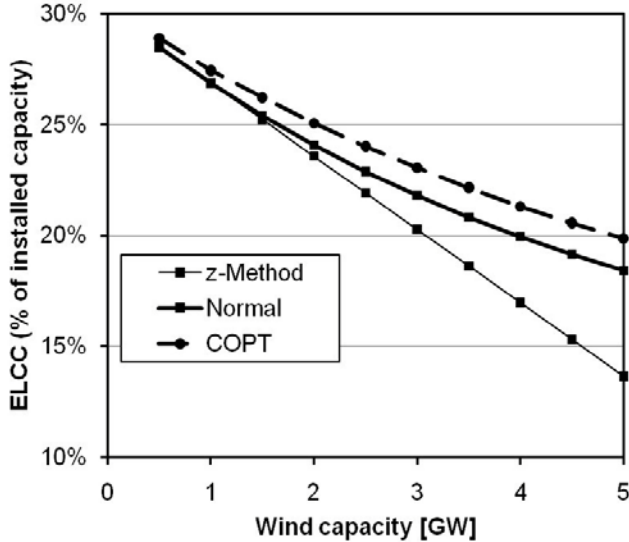


Fig. 6. ELCC as determined by z-method, preferred method and preferred method with normal distribution for conventional plant

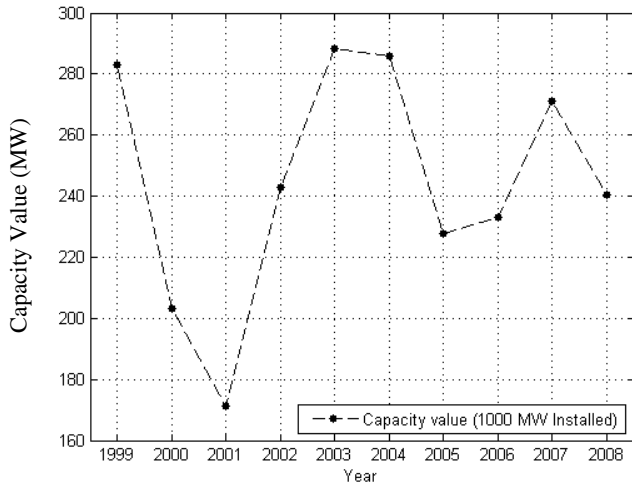


Fig. 7. Variation of Wind ELCC on Irish system over multiple years [25]

have 3,300 MW installed capacity, of which 600 MW were assumed to be off-shore. Available historical meteorological data for the same years were used to create time series for hourly wind power generation at different sites. The time synchronized data for loads and output wind power were used in the analysis to maintain their correlation. The LOLE analysis was performed while considering the transfer limits on the tie-lines between the pairs of interconnected areas. The hourly loads for 2001 and 2002 have been modified to be in per unit based on the 2008 peak load.

Results show that most of the reduction in LOLE comes from the 600 MW offshore site. The sites to the west of a major system transmission interface have minimal effect on LOLE due to congestion in the transmission. For 2001, the ELCC for the 3,300 MW of wind generation is 270 MW, i.e., 8% of nameplate capacity, if the transmission constraints are removed the ELCC increase to 720 MW (22% of nameplate capacity). Overall, the onshore ELCC is about 10% with the offshore ELCC rising to 40%, as shown later in Fig. 7. Some of the LOLE analysis results are shown in Fig. 5.

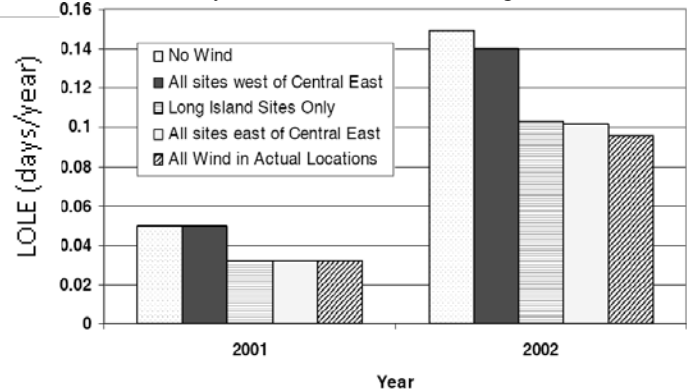


Fig. 8. NY State LOLE analysis results [26]

C. Minnesota State Study

The study was performed in 2006 [14]. Different levels of wind generation 3,441 MW, 4,582 MW and 5,688 MW which correspond to 15%, 20% and 25% as a percentage of the forecasted Minnesota retail electric sales in the year of 2020 were assumed. The peak demand in the system was 15,630 MW. Conventional generation was expanded to meet the criteria of LOLE of 1 day/10 years for the year of 2020.

Wind generation was represented as negative load as per the preferred method. The analysis was conducted for three different versions of year 2020, where the hourly wind and load patterns are based on the historical years 2003, 2004, and 2005. The LOLE analysis was performed using a commercial reliability evaluation software package to construct the COPT for the non wind and the three wind penetration scenarios. The preferred method described in Section II was used to evaluate capacity value for each penetration scenario. The study results are summarized in Fig. 6. It can be seen that the effective capacity of wind generation can vary significantly year-to-year. The ELCC of the wind generation corresponding to 15% 20% and 25% wind penetration ranges from approximately 5% to just over 20% of nameplate capacity. Meteorological conditions are the most likely explanation for the trend in the ELCC by year. The highest ELCC values were obtained in 2003 as this year shows the best correlation between wind production during the highest load hours while the lowest ELCC values were obtained in 2005 as this year exhibits the poorest correlation.

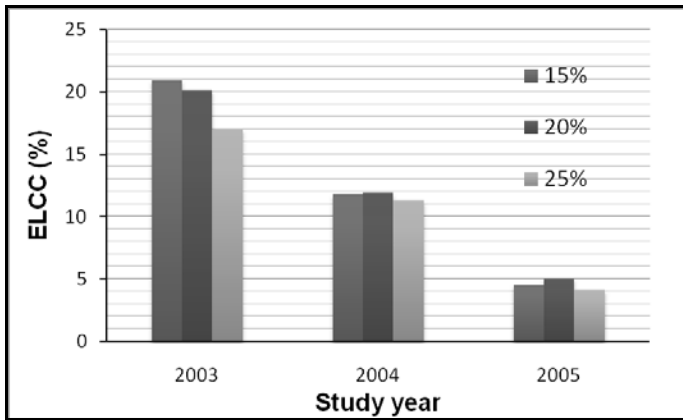


Fig. 9. The ELCC values for 3 different levels of wind penetration for the Minnesota State study [14]

D. Irish Wind Study

The Irish wind study from 2004 examines the impact of Irish wind power generation on the conventional power plants [27]. The peak load on the system in 2004 was approximately 4,500 MW. The calculated capacity value of wind generation is equal to the amount of conventional capacity that can be omitted whilst maintaining the same LOLE. This definition of capacity value is distinct from that recommended here, where capacity value is defined in terms of additional load. The definition in terms of additional conventional capacity requires the definition of a notional typical conventional unit to measure the ELCC against. The hourly wind power generation is modeled as negative demand and added to the hourly load profile capturing corresponding correlation effects. This corresponds to the preferred methodology in Section II. Measurements of 18 onshore wind stations and 1 offshore station for the year of 2001 serve to model the wind power profile. The reference LOLE is 8 h in one year. This is the accepted generation adequacy standard for Ireland. It is the target employed by the TSO for long term generation planning calculations using assumed load growth and planned generator FORs [2]. It is also employed for more short term considerations such as calculating the generation adequacy for the following peak demand season. Given the increasing penetration of wind energy in Ireland, the ELCC of wind is of particular relevance. A capacity market is also operated in Ireland and is based on the calculation of monthly/seasonal ELCC. This calculation is the basis for the allocation of the capacity credit funds to the market participants.

Capacity values of wind generation in a 5 GW peak system and a 6.5 GW peak system consisting of more and more modern conventional power plants are calculated. In the former system the capacity value of 0.5 GW installed wind capacities is 34% of installed capacity. Assuming 1.5 GW it decreases to 23% of installed capacity. The same amount of capacities show a slightly lower capacity value of 22% in the second system dropping to 14% with 3.5 GW of installed wind capacities.

A report on the state of the art of wind integration by the IEA Wind Task 25 compiled the results of these and other wind integration studies into a single document and provides useful comparisons between methods and countries/regions [28]. It is apparent from the results described above that the

capacity value is dependent on the method employed but it also depends on the specific characteristics of the region/country. In particular, the characteristics of the wind regime and the characteristics of the demand profile, e.g. whether peak demand occurs in winter or summer [29-30].

V. DISCUSSION

There remain a number of issues surrounding the calculation of capacity values. These range from the representation of other generation types in the calculation method to the data requirements for calculations.

The use of long-term synchronized load and wind data is encouraged, keeping in mind the difficulty in using old load profile curves to represent the future. However, capacity value calculations are normally based on data sets over limited time periods, but the statistics of the available data sets may not be representative. This becomes more critical if several stochastic variables are present. The relationship patterns between wind and peak load for example vary strongly over different years. It would be valuable to have some estimation of the possible deviations of capacity values that are related to different time periods and hence quantify the impact that limited data sets can have on the calculation results.

Currently, the inclusion of maintenance schedules in the preferred calculation can have an influence on the calculated LOLE. Maintenance schedules in reality may have some flexibility, and if faced with a severe capacity deficit, scheduled maintenance can in some instances be deferred. This may call into question the use of deterministic maintenance schedules in capacity value calculations and would be worth investigating.

The applications of capacity value are in planning. However, the unique characteristics of wind power are giving rise to new interactions between the planning and operations timeframes. Calculations based on a weekly or daily timeframe, with very precise knowledge of system conditions, are necessarily different to those performed under the greater uncertainty of a planning timescale, thus leading to a new concept related but distinct from capacity value. Specific factors that may have influence in this regard are maintenance schedules, unit ramping and certain transmission constraints.

This paper has covered the treatment of wind resources only. As they move towards commercial development, the capacity value of other variable resources such as wave, solar and tidal should also be considered. This will require development of both appropriate system risk assessment techniques, and also the necessary resource models for use as inputs. These calculations will present differing challenges; wave, like wind, is a stochastic resource, whereas tidal is intermittent but predictable [31].

VI. CONCLUSIONS AND RECOMMENDATIONS

This paper has described a preferred method for calculation of capacity value of wind generation. Key metrics employed in the calculation have been defined. The employment of time synchronized load and wind power output data that captures their correlation is vital. Representation of wind as a two state probability model or assessment of wind's capacity value at

peak times is inadequate. Factors such as the correlation between different wind sites and with the load, the geographical area and the target reliability level have been shown to have a considerable impact on the capacity value.

A number of the common approximate methods for capacity value of wind have been described. The accuracy of these methods is varied and while some may be useful given limited data, it is important to be clear about the approximations being made. Several international studies in this area have been undertaken. A summary of the results of these studies has been given, illustrating that diverse methods and wind resources lead to a wide range of values for the capacity value of wind power. Further to this, new analysis showing the comparison of the preferred method to some of the approximate methods has been given.

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