A New Approach to Quantify Reserve Demand in Systems With Significant Installed Wind Capacity

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***Abstract*—With wind power capacities increasing in many electricity systems across the world, operators are faced with new problems related to the uncertain nature of wind power. Foremost of these is the quantification and provision of system reserve. In this paper a new methodology is presented which quantifies the reserve needed on a system taking into account the uncertain nature of the wind power. Generator outage rates and load and wind power forecasts are taken into consideration when quantifying the amount of reserve needed. The reliability of the system is used as an objective measure to determine the effect of increasing wind power penetration. The methodology is applied to a model of the all Ireland electricity system, and results show that as wind power capacity increases, the system must increase the amount of reserve carried or face a measurable decrease in reliability.**

***Index Terms*—Forecasting, power generation faults, power system security, wind power generation.**

NOMENCLATURE

$\Phi(\mathrm{x})$	Normalized Gaussian distribution function.
$\rho_{m,n}$	Correlation coefficient of wind power forecast errors between farms m and n.
$\sigma_{m,h}$	Standard deviation of wind power forecast error for farm m in hour h.
$\sigma_{wind,h}$	Standard deviation of total wind power forecast error in hour h.
$\sigma_{load,h}$	Standard deviation of load forecast error in hour h.
$\sigma_{total,h}$	Standard deviation of total system forecast error in hour h.
F	Number of wind farms.
G	Number of generators.
Hr	Number of hours until the reliability of the system is restored after a generator outage.
LSI	Load shedding incidents expected per year.
FOR	Forced outage rate.
$MTTR$	Mean time to repair.
$FOP_{i,h}$	Full outage probability. The probability of generator i becoming fully unavailable in hour h.
$POP_{i,h}$	Partial outage probability. The probability of generator i becoming partially unavailable in hour h.
PLS_h	Average probability of load shedding in hour h.
$PLSNO_h$	Probability of load shedding during normal operation in hour h.
$PLSFO_{i,h}$	Probability of load shedding after the full outage of generator i in hour h.
$PLSPO_{i,h}$	Probability of load shedding after the partial outage of generator i in hour h.
$Pnafo_{i,h}$	Power not available after a full outage from generator i in hour h.
$Pnapo_{i,h}$	Power not available after a partial outage from generator i in hour h.
R_h	Reserve carried by the system in hour h.

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I. INTRODUCTION

THE quantification of system reserve has, until recently, been a relatively simple, and largely deterministic process. In many systems, the amount of reserve carried at any time is just enough to cater for the loss of the largest infeed. Although there is some uncertainty due to load forecast errors, system operators are familiar with this and can generally manage it. This approach does not guarantee a secure system at all times, but rather assumes any loss of generation greater than the largest infeed is so infrequent that it is deemed unnecessary to carry extra reserve all year round. When such an event does occur the system will have to shed some load. This simple approach to quantifying reserve needs has proven successful in many systems all over the world. However, as wind power penetration grows, there are concerns that the uncertain nature of wind power output will mean that amounts larger than the largest infeed are lost more frequently as significant unforecasted wind variations may coincide with large generator trips.

In [1] the author considers wind speed and load forecasts errors and ramp rates of conventional thermal units to determine system reserve margins in the wind-hydro-thermal interconnected Swedish electricity system. Consideration is given to the correlation of wind farm forecasts within a region and between different regions and links the reserve levels to a probability of too low a frequency due to load and wind fluctuations. The Swedish system has a need for a reserve pool for frequency control separate to that of the reserve allocated for generator and transmission line trips. However, this is not the case in many other electricity systems. Persuad *et al.* [2] examine the impact of wind power capacity on generator loading levels, system reserve availability and generator ramping rates. The authors suggest the availability of system reserve will depend on whether the predicted wind power is incorporated into the unit commitment process. Dany [3] attempts to quantify the technical consequences of high wind penetrations in terms of primary, secondary and long-term reserve as they apply to the interconnected German power system and suggests it will cause a substantial change in the demand for certain types of reserve. Interestingly, the author also suggests a need for negative secondary reserve to avoid a surplus of power when wind farms produce a large unforecasted increase in power production. In [4], Watson *et al.* evaluate the impact of different forecasting techniques on fossil fuel savings and spinning reserve requirements on a large scale electricity system. They conclude that the benefits in both fossil fuel savings and spinning reserve requirements can be gained by the use of more sophisticated forecasting techniques than the persistence method. However, the increased spinning reserve requirement was calculated as a simple fraction of the predicted wind power or wind power prediction error. In [5], the authors discuss the modification of unit commitment, economic dispatch, and frequency controls when wind generation capacity is significant and attempts to determine a wind power penetration constraint based on a worst case wind generation scenario. The authors however, do not consider the possible benefit forecasting may play in the system operation. O'Dwyer *et al.* [6] assess the extent to which wind energy would be technically feasible and economically attractive on the isolated Irish electricity system. It analyzes environmental and economic impacts along with capacity and frequency control issues from a 1990 perspective. However, like [5] it fails to consider the contribution that forecasting may have on the provision of frequency control reserve.

When quantifying the reserve needed on the system, the reliability of the system must be used as an objective measure to assess required reserve under different conditions. In this paper a methodology is proposed that will consider the uncertainty in the load and wind power forecasts along with the probability of losing generation to quantify the required system reserve level for a specified level of system reliability. This methodology is then applied to a model of the all Ireland system with significant quantities of wind capacity, taking into consideration the characteristics of the latest wind power forecasting techniques.

II. Methodology

The methodology presented here is a revision and expansion of that in [7] and can quantify the reserve demands of a system with significant wind power penetration. Reserve on a system is needed to cater for any possible unexpected generation deficit. This can be caused by generator outages, unexpected increases in the load or unexpected decreases in wind power production. The actual variability of the load and wind power itself will not impact on the system reserve levels, however, the accuracy of the load and wind power forecasts will have a significant bearing on the system reserve levels as they will introduce greater uncertainty on to the system. It should be noted here that this methodology quantifies the amount of reserve needed on the system and assumes that the reserve acts instantaneously to any generation deficits. Any analysis into the actual nature of the response of the reserve is a subject for detailed dynamic modeling [8], [9]. However, the methodology may be applied to produce reserve targets for different classes of reserve, i.e., spinning, secondary etc., based on the time frames over which these reserves are assumed to respond.

A. System Reliability Criterion

There are many different reliability criteria used in power systems analysis [10], [11]. Most system reliability analysis focuses on generation adequacy calculations, which consider the probability of load and generation *being* out. The methodology here, which is suited to system operation and dispatch, considers the probability of generation and load *going* out. It is this subtle difference in approach that allows the effect of wind and load variations to be included in the reserve calculations. In this paper the reliability criterion is defined as being the number of load shedding incidents (LSI) tolerated per year, where a load shedding incident is defined as an incident when there is not enough reserve to meet a generation shortfall. The LSI can be related to the loss of load expectation (LOLE) reliability criterion, which is used in many electricity systems, by multiplying by the average time that load is shed for. Both the LSI and LOLE reliability criteria quantify the likelihood of failure but do not quantify the magnitude of load shedding. Although the magnitude of load shedding incidents is not dealt with in this paper, the methodology can be adapted to allow for the extent of load shedding to be examined.

B. Generator Outages

The methodology considers the probability of both full and partial generator outages on an hourly basis. The full outage probability (FOP) of a unit is the probability that the unit will stop providing all of its current output in an hour period. Here it is assumed that the trip causes the units output to be instantaneously unavailable. The hourly FOP of a unit can be related to the forced outage rate (FOR) and mean time to repair (MTTR) as

$$FOP = \frac{FOR}{MTTR}. \quad (1)$$

Partial outages of units are modeled in a similar way to the full outages. The partial outage probability (*POP*) is the probability of an instantaneous loss of a portion of the generation in an hour period. This methodology adopts a one state partial outage approach [10].

C. Wind Power and Load Forecast Errors

Like any forecast, load forecasts have an error associated with them. Due to the highly repetitive nature of the daily load profile, load forecast errors are not especially sensitive to the forecast horizon and are usually proportional to the size of the load at any given hour. The load forecast error in hour h can be modeled as a Gaussian stochastic variable with a mean of zero and a standard deviation of $\sigma_{load,h}$.

Wind power forecast errors generally increase as the forecast horizon increases. Like load forecast errors the wind power forecast error for the system in hour h can be modeled as a Gaussian stochastic variable with a mean of zero and a standard deviation of $\sigma_{wind,h}$.

Since it is assumed both the load and wind power forecast errors are uncorrelated Gaussian stochastic variables then the standard deviation of the total system forecast error $\sigma_{total,h}$ can be given by

$$\sigma_{total,h} = \sqrt{\sigma_{wind,h}^2 + \sigma_{load,h}^2}. \quad (2)$$

D. Reserve Calculation

The methodology presented in this paper relates the reserve level on the system in each hour to the reliability of the system over the year. The reserve requirement in every hour will vary as the generator dispatch and forecast errors vary; therefore the

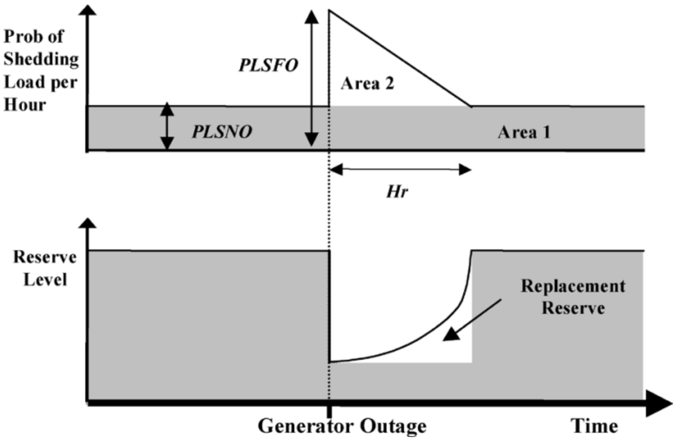

Fig. 1. Illustrative plots of probability of load shedding and reserve level against time during a full generator outage.

reserve level must be related to the reliability of the system over one hour. It is assumed here that the reserve is allocated in such a way during the year as to keep the average risk of having a load shedding incident in each hour the same for all hours (i.e., each hour is operated such that if the year was comprised of 8760 such hours then the expected number of load shedding incident would be LSI). For any hour h, the probability of load shedding (PLS_h) is the yearly reliability criterion divided by the number of hours per year (3)

$$PLS_h = \frac{LSI}{8760}. \quad (3)$$

The approach considers having a load shedding incident in three ways:

1) by having just an unforecasted wind and load variation greater than the system reserve level;
2) by having just one generator trip (full or partial) and an unforecasted wind and load variation greater than the system reserve level;
3) by having a generator trip and an unforecasted wind and load variation some time directly after a previous generator trip.

Due to the small nature of the generator outage rates (FOP and POP), the probability of having three or more generator outages in a short period of time is small and will not meaningfully contribute to the number of load shedding incidents experienced over a year. The number of load shedding incidents per year will correspond to the sum of the probabilities of having a load shedding incident in each hour. There are two parts that contribute to this. The first is the probability of having a load shedding incident under normal hours of operation (*PLSNO*), illustrated by Area 1 in Fig. 1. The second is the increased probability of having a load shedding incident in the time after the outage of a unit. This is illustrated by Area 2 and corresponds to the case when the system is operating with a reduced amount of reserve due to the outage of a unit. It is assumed that the reliability of the system is re-established in a linearly fashion by restoring the reserve level over Hr hours.

The probability of shedding load during a normal hour of system operation (*PLSNO*) comprises of three components, as shown in (4). $\Phi(\mathrm{x})$ denotes a normalized Gaussian distribution function.

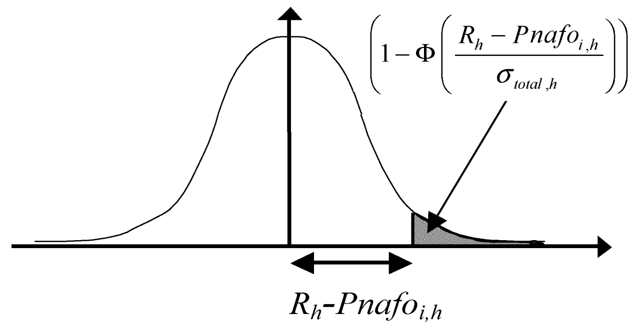

Fig. 2. Gaussian distribution of total system forecast error in hour h. Gray area corresponds to the probability of having a forecast error greater than the system reserve level minus the power lost during the full outage of generator i.

1) The probability of not having any sort of generator trip while having an unforecasted wind and load variation greater than the system reserve level. This scenario corresponds to the first term in (4).
2) The probability of having just one full generator trip and an unforecasted wind and load variation greater that the system reserve level. This scenario corresponds to the second term in (4) and is illustrated in Fig. 2 where the gray area corresponds to the probability of having a wind and load variation greater than the system reserve level (R_h) minus the power not available after the full outage of generator i in hour h $(Pnafo_{i,h})$.
3) The probability of having just one partial generator trip and an unforecasted wind and load variation greater that the system reserve level. This scenario is similar to that in 2 and corresponds to the third term in (4)

$$\begin{aligned} PLSNO_h = & \left(\prod_{i=1}^{G}(1-FOP_{i,h})\right)\left(\prod_{i=1}^{G}(1-POP_{i,h})\right) \\ & \times\left(1-\Phi\left(\frac{R_h}{\sigma_{total,h}}\right)\right) + \sum_{i=1}^{G} FOP_{i,h} \\ & \times\left(\prod_{\substack{j=1\\ j\neq i}}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\ j\neq i}}^{G}(1-POP_{j,h})\right) \\ & \times\left(1-\Phi\left(\frac{R_h - Pnafo_{i,h}}{\sigma_{total,h}}\right)\right) + \sum_{i=1}^{G} POP_{i,h} \\ & \times\left(\prod_{j=1}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\ j\neq i}}^{G}(1-POP_{j,h})\right) \\ & \times\left(1-\Phi\left(\frac{R_h - Pnapo_{i,h}}{\sigma_{total,h}}\right)\right). \end{aligned} \quad (4)$$

It should be noted here that a generator outage is a discrete event and may or may not happen in any given hour. This contrasts with the continuous nature of the wind and load variations. It is assumed in this methodology that reserve is replaced after a generator outage over Hr hours while reserve used in offsetting unforecasted wind and load variations is not.

It can be seen from (4) that $PLSNO_h$ monotonically decreases with increasing R_h. Since $PLSNO_h$ directly determines the reserve level on the system, and the maximum risk of load shedding directly after each generator outage (*PLSFO* and *PLSPO*) depends on the reserve on the system before that outage, then $PLSNO_h$ directly determines the values of *PLSFO* and *PLSPO*. The probability of load shedding directly after the full and partial outage of unit k in hour h ($PLSFO_{k,h}$ and $PLSPO_{k,h}$) are shown in (5) and (6). The extra term in (6) is to account for the probability of having a full outage of the remaining output form the unit that has just previously partially tripped

$$\begin{aligned} PLSFO_{k,h} &= \left(\prod_{\substack{i=1\\i\neq k}}^{G}(1-FOP_{i,h})\right)\left(\prod_{\substack{i=1\\i\neq k}}^{G}(1-POP_{i,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnafo_{k,h}}{\sigma_{total,h}}\right)\right)+\sum_{\substack{i=1\\i\neq k}}^{G}FOP_{i,h} \\ &\times\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-POP_{j,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnafo_{k,h}-Pnafo_{i,h}}{\sigma_{total,h}}\right)\right)+\sum_{\substack{i=1\\i\neq k}}^{G}POP_{i,h} \\ &\times\left(\prod_{\substack{j=1\\j\neq k}}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-POP_{j,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnafo_{k,h}-Pnapo_{i,h}}{\sigma_{total,h}}\right)\right) \end{aligned} \quad (5)$$

$$\begin{aligned} PLSPO_{k,h} &= \left(\prod_{i=1}^{G}(1-FOP_{i,h})\right)\left(\prod_{\substack{i=1\\i\neq k}}^{G}(1-POP_{i,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnapo_{k,h}}{\sigma_{total,h}}\right)\right)+\sum_{\substack{i=1\\i\neq k}}^{G}FOP_{i,h} \\ &\times\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-POP_{j,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnapo_{k,h}-Pnafo_{i,h}}{\sigma_{total,h}}\right)\right)+\sum_{\substack{i=1\\i\neq k}}^{G}POP_{i,h} \\ &\times\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\j\neq i\\j\neq k}}^{G}(1-POP_{j,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnapo_{k,h}-Pnapo_{i,h}}{\sigma_{total,h}}\right)\right)+FOP_{k,h} \\ &\times\left(\prod_{\substack{j=1\\j\neq k}}^{G}(1-FOP_{j,h})\right)\left(\prod_{\substack{j=1\\j\neq k}}^{G}(1-POP_{j,h})\right) \\ &\times\left(1-\Phi\left(\frac{R_h-Pnapo_{k,h}-(Pnafo_{k,h}-Pnapo_{k,h})}{\sigma_{total,h}}\right)\right). \end{aligned} \quad (6)$$

The average probability of load shedding in hour h (PLS_h), shown in (7) comprises of both the probability that load will be shed under normal operation of the system and that load will be shed during the period after the outage of each unit. The contribution from the later comprises a series of triangular areas, shown as Area 2 in Fig. 1, multiplied by the probability of them occurring over the hour period

$$\begin{aligned} PLS_h =& PLSNO_h + \frac{1}{2}(Hr) \\ &\times[FOP_{1,h}, FOP_{2,h},\ldots\ldots\ldots FOP_{G,h}] \\ &\times\begin{bmatrix} PLSFO_{1,h}-PLSNO_h\\ PLSFO_{2,h}-PLSNO_h\\ \vdots\\ \vdots\\ PLSFO_{G,h}-PLSNO_h \end{bmatrix} + \frac{1}{2}(Hr) \\ &\times[POP_{1,h}, POP_{2,h},\ldots\ldots\ldots POP_{G,h}] \\ &\times\begin{bmatrix} PLSPO_{1,h}-PLSNO_h\\ PLSPO_{2,h}-PLSNO_h\\ \vdots\\ \vdots\\ PLSPO_{G,h}-PLSNO_h \end{bmatrix}. \end{aligned} \quad (7)$$

The PLS_h can be simply related back to the reliability criterion over the year as shown in (3). Since (R_h) cannot be explicitly expressed in terms of the other variables, for a given $PLSNO_h$, R_h is solved using the MATLAB optimization toolbox. This allows a solution to be found for any LSI by searching the solution space, varying $PLSNO_h$ between its lower bound of zero and its upper bound of ($LSI/8\,7\,6\,0$).

Other applications of the methodology not shown in this paper include using it to produce a reserve demand curve based on the probability of needing certain amounts of reserve and the value of lost load (VOLL). It can also be used to create a probability distribution to examine the extent of load shedding incidents for any particular hour and reserve level.

III. Application to All Ireland Electricity System

The all Ireland electricity system consists of both the Northern Ireland and Republic of Ireland systems. It has an installed capacity of approximately 7500 MW and just one 500-MW HVDC interconnector to Scotland. The relatively small and weakly interconnected nature of the system make frequency control issues a higher priority than they would be in other systems. Although both the Republic of Ireland and Northern Ireland systems are currently operated separately, there are reserve sharing agreements between the two jurisdictions. This makes the issue of the impact of wind power penetration on reserve levels an all Ireland problem. The island of Ireland has one of the best wind power resources in the world. Although installed wind capacity at the moment is relatively small, it is likely that there will be considerable development in wind power over the coming years to meet various government and international renewable energy targets [12]–[14]. It is expected that approximately 1500 MW of wind capacity will be installed on the all Ireland system by 2010.

The methodology, presented in Section II is applied to a single bus model of the all Ireland system. Sixty-five individual generators and the HVDC interconnector are considered in the system which is based in the system as it was at the beginning of 2003. Additional quantities of wind are added to the system to examine the effects that increased wind power penetration has on the reserve levels. The largest single unit has a maximum capacity of 408 MW. The probability of outages (FOPs and POPs) of the units in the Republic of Ireland system were derived from historical data. These were taken to be the number of times the unit had full and partially tripped in the year divided by the number of hours the unit was generating in the year. The full outage probabilities, FOPs range from about 0.003 for the least reliable units to about 0.0006 for the most reliable units. The outage probabilities of the units in Northern Ireland were based on those of similar units in the Republic of Ireland. Typical generator dispatches were based on historical data available from ESB National Grid [15]. It is assumed that the reliability of the system is restored in 2 hours after a generator outage.

Many system operators are currently concerned with the possibility of many wind farms tripping off simultaneously due to a single transmission fault. This behavior can be incorporated into the methodology if assessments are made of the quantity and probability of various amount of wind capacity being simultaneously disconnected. Currently in Ireland new wind farms will be required to have the technical ability to stay connected during such transmission faults [16], and it is for this reason that simultaneous tripping of wind farms is not included in this particular study.

A. Wind Power Forecasting

The impact additional wind capacity will have on the system reserve levels will depend on the increased uncertainty that it presents to the system in the form of larger wind power forecast errors. Various different factors contribute to the overall wind power forecast error such as the accuracy of the forecasts for individual wind farms, the correlation of wind power forecast errors between different wind farms, the forecast horizon, the size of the individual wind farms and their geographical dispersion around the country. Much work has been done in assessing the performance of wind forecasting techniques in Ireland [17]–[19] and in general the wind power forecast error can be expressed as a function of the forecast horizon. Fig. 3 shows the typical standard deviation of the wind power forecast error for an individual farm against the forecast horizon. This is based on results from a physical wind power forecasting tool [17] and results from numerical/fuzzy forecasting system [19]. Both techniques gave reasonably similar results which is taken here to be a measure of the state of wind power forecasting in Ireland at present.

Correlation between individual wind farms' forecast errors is a very important issue and has the potential to significantly increase the overall uncertainty that the system is exposed to from wind capacity. It should be noted that this correlation is distinct from the correlation between individual wind farms' forecasted outputs, which do not expose the system to greater levels of uncertainty. It has been shown in [17] that the correlation between wind power forecast errors of individual wind farms is strongly dependent on the distance between the wind farms. It has also been shown that the forecast horizon also has an effect on the correlation. However, this has a small effect over

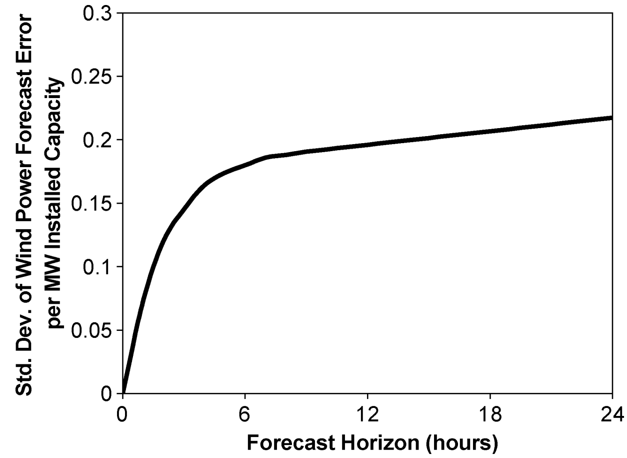

Fig. 3. Plot of typical standard deviation of wind power forecast errors per megawatt of installed capacity for an individual farm versus the forecast horizon.

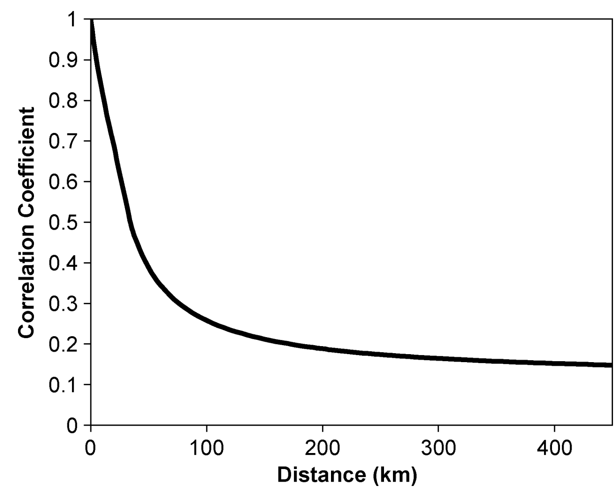

Fig. 4. Plot of correlation coefficient between individual wind farms' forecast errors versus distance.

longer forecast horizons and very little work has been done on examining these correlations for forecast horizons shorter than 6 hours. It is for these reasons that in this study, the correlation of wind power forecast errors are assumed to be solely a function of the distance between the wind farms. Based on work done in [17], Fig. 4 shows the correlation coefficient between individual wind farms' forecast errors against the distance between the wind farms.

From analysis of wind power projects still in development [20] it looks likely that the west and north coasts along with other mountainous areas further inland will be the main focus for future on-shore wind power development. Fig. 5 illustrates the assumed installed wind capacity on the island, as a percentage, on a county by county basis. This was based on figures given in [21] and [22].

When calculating the overall wind power forecast error for a given installed capacity, wind farms of typical size were distributed among the counties in accordance with Fig. 5. Wind farms sizes were based on all existing farms, and farms in the planning process [23], [24]. From this the distance between wind farms can be estimated and the standard deviation of the overall wind power forecast error for hour h, $(\sigma_{wind,h})$ can be

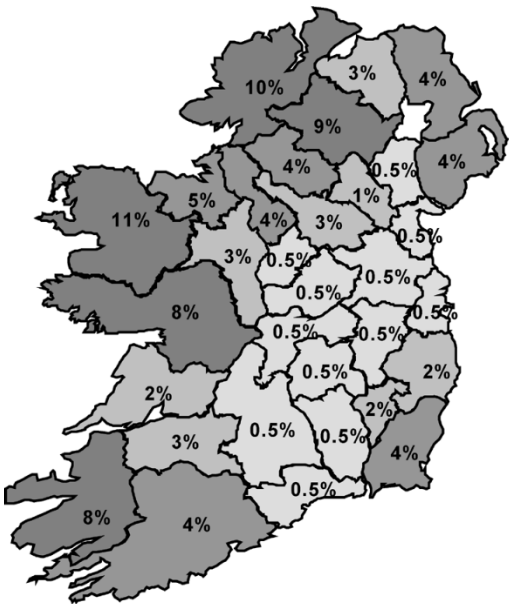

Fig. 5. Future per-county distribution of installed wind power capacity in percent.

calculated from (8), where F is the number of wind farms, $\sigma_{m,h}$ is the standard deviation of wind power forecast error for farm m in hour h and $\rho_{m,n}$ is the correlation coefficient of wind power forecast errors between farms m and n

$$\sigma_{wind,h} = \sqrt{\sum_{m=1}^{F} \sigma_{m,h}^2 + 2\sum_{n=1}^{F} \sum_{m=n+1}^{F} \rho_{m,n}\sigma_{m,h}\sigma_{n,h}}. \quad (8)$$

Most analysis of wind power forecasting accuracy concentrates on the average standard deviation of the forecast errors. However, not all hours of the year are equally forecastable, since the stability of the weather conditions and other factors may vary. Recent forecasting work [18] has developed a weather stability index called the "meteo-risk index" and has established a roughly linear relationship between this index and the magnitude of the forecast errors for individual wind farms. Based on the frequency of occurrence of different weather situations as expressed by the meteo-risk index, and its effect on the standard deviation of the wind power forecast errors, best- and worst-case scenarios have been established which correspond to the most accurate and least accurate that the total wind power forecast error is ever likely to be. Fig. 6 shows the standard deviation of the total wind power forecast error for the best- and worst-case scenarios along with the average case versus the installed wind capacity for a forecast horizon 6 hours ahead.

B. Total System Forecast Error

Based on analysis of historical data [15], the standard deviation of the load forecast errors on the all Ireland system is taken to be 75 MW. Using this and the standard deviation of the total wind power forecast error shown in (8), the standard deviation of the total system forecast error can be calculated from (2).

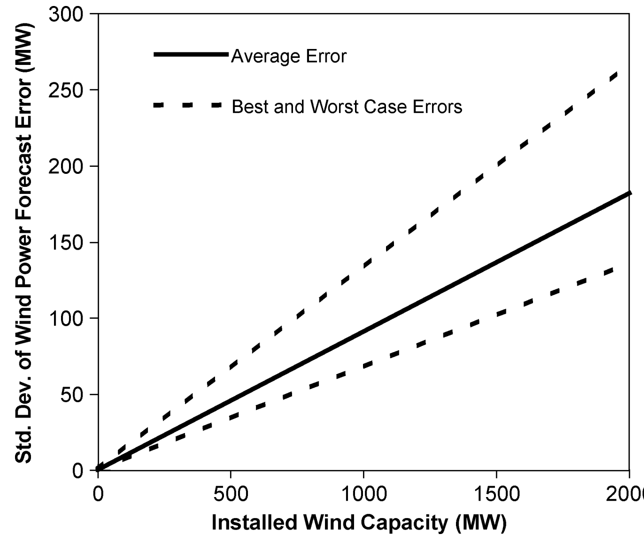

Fig. 6. Standard deviation of average wind power forecast error along with the best- and worst-case scenarios versus installed wind capacity for a forecast horizon of 6 hours.

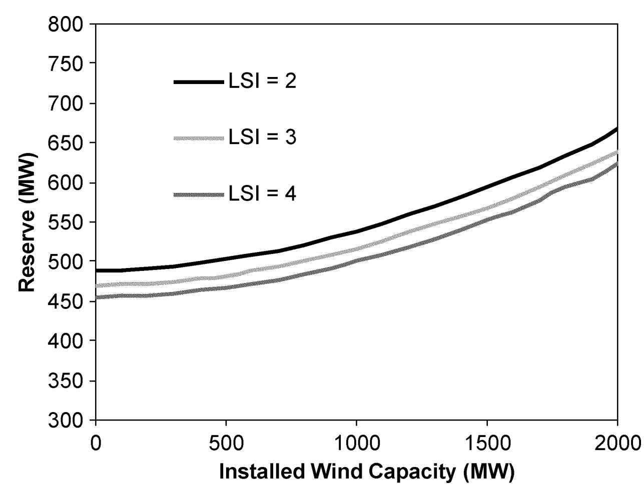

Fig. 7. System reserve level for a various number of load shedding incident per year and a forecast horizon of 3 hours against wind power penetration.

IV. Results and Discussion

A. Calculation of Reserve

Results here are based on a one hour period when the conventional generating units on the all Ireland system were generating 4459 MW. Fig. 7 shows the required reserve level for a forecast horizon of 3 hours and for different numbers of load shedding incidents per year against increasing wind power penetration.

Fig. 7 shows that as the wind power penetration increases then the system reserve level must also increase or the system will suffer a decrease in reliability. It can be seen that 1500 MW of installed wind capacity causes roughly a 20% increase in the need for reserve.

Fig. 8 shows the effect that the forecast horizon has on the required reserve level for a wind power capacity of 1500 MW under different reliability criterions. As the forecast horizon increases the standard deviation of the total wind power forecast error increases causing a greater need for reserve.

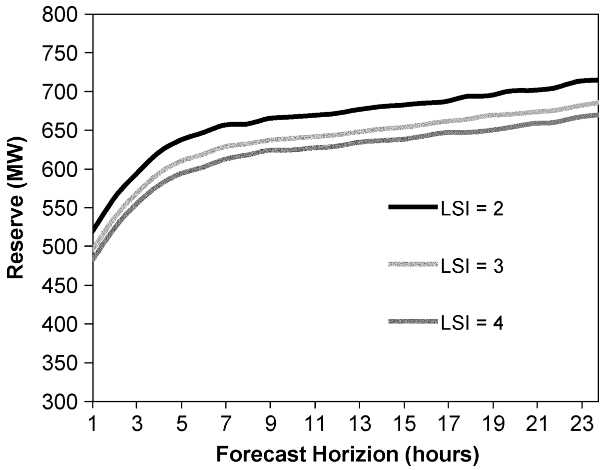

Fig. 8. System reserve level for an installed wind capacity of 1500 MW and for various load shedding incidents per year versus the forecast horizon.

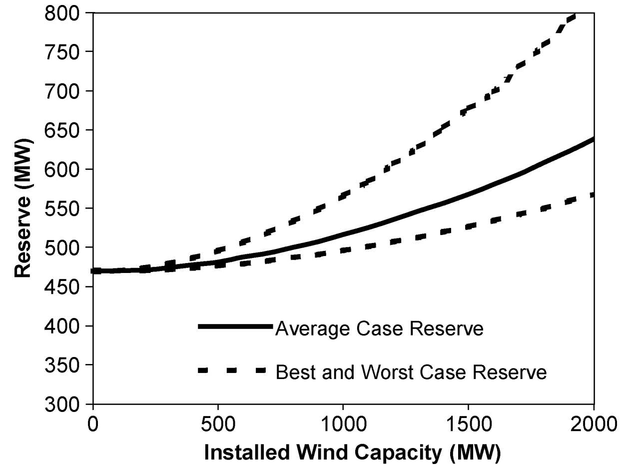

Fig. 9. System reserve level for the average, best- and worst-case scenarios for a forecast horizon of 3 hours versus installed wind capacity for a reliability criterion of three load shedding incidents per year.

Usually in electricity systems, the operating decisions for any particular hour are made some time before that hour, e.g., hour ahead, day ahead, etc. The amount of reserve that is dispatched or committed for a certain hour is the amount that is deemed necessary at the time the operating decision is made. With a substantial wind power penetration, Fig. 8 illustrates the benefits of making the dispatch decision closer to real-time when the standard deviation of the wind power forecast error is smaller causing a reduction in the amount of reserve required. However successfully operating a system closer to real time will require a reasonably flexible set of conventional plant which are able to respond to signals and instructions over short time frames.

Fig. 9 shows a plot of the required system reserve level for a LSI of 3 versus the installed wind capacity for the average case along with the best and worst case scenarios, as outlined in Section III. With an installed wind power capacity of 1500 MW the best case scenario shows a 12% increase in the amount of reserve needed above the case with no wind, while the worst case scenario shows an increase in the need for reserve of 44%. However, it must be stressed that that this is the very worst case scenario and would be expected to occur extremely rarely.

From Fig. 9 it can be seen that for a reliability criterion of three load shedding incidents per year and a forecast horizon of 3 hours, the reserve needed on the system with no wind capacity is 470 MW. With 1000 MW of wind capacity the system requires 516 MW. This is a 10% increase. If the load forecast error were to be excluded from the calculation then the system would need to carry 468 MW of reserve to cover for just the wind power forecast error and unit outages. This shows that with a forecast horizon of 3 hours the uncertainty associated with 1000 MW of wind capacity has a similar impact in terms of reserve as the uncertainty in the load.

B. Conventional Reserve Requirements

In general electricity systems have several categories of reserve defined over different time frames. This section will examine the impacts that wind penetration will have on conventional reserve categories based on those used in Republic of Ireland system (see Table I). It should be noted that the reserve categories defined in the Republic of Ireland system are exclusive of each other and are only required to generate within the time frame shown after an event. The nature of the variation of wind power output over time periods as short of 15 s has not been the subject of study in Ireland. Over short periods of time the standard deviation of the total system forecast error is heavily dependent on the standard deviation of the wind power and load variations, as sophisticated forecasting techniques can offer little improvement on the persistence method over such time frames [17], [18]. For time periods less than one hour, it is assumed that the variation of the total system forecast error/variation over t seconds (σ_t) is related to the standard deviation of the total system forecast error/variation for a one hour forecast horizon $(\sigma_{1\ Hour})$ as follows:

$$\sigma_t = \sqrt{\frac{t}{3600}}\sigma_{1\ Hour}. \tag{9}$$

TABLE I
TIME FRAMES OF CONVENTIONAL RESERVE CATEGORIES AND STANDARD DEVIATION OF TOTAL SYSTEM FORECAST ERROR WITHIN TIME FRAME FOR 1500 MW OF INSTALLED WIND CAPACITY

Category	Time Frame	σ_{total}(MW)
Primary	5 - 15 sec	6.0
Secondary	15 - 90 sec	14.8
Tertiary 1	90 sec - 5 min	27.0
Tertiary 2	5 - 20 min	54.0
One Hour	20 min - 1 hour	93.4

In [25], results are presented from a program that measured the variations in wind power output over various time frames. The relationship of the variations over different time frames were found to generally support the assumption made in (9). Table I shows the different reserve categories and the time frames they are to respond within. The standard deviation of the total system forecast error is very small over 15 s and gradually gets larger as the time frame increases.

In the current reserve requirements in Ireland it is assumed that the dynamic response of the load to a frequency event reduces the need for primary and secondary reserve. This response

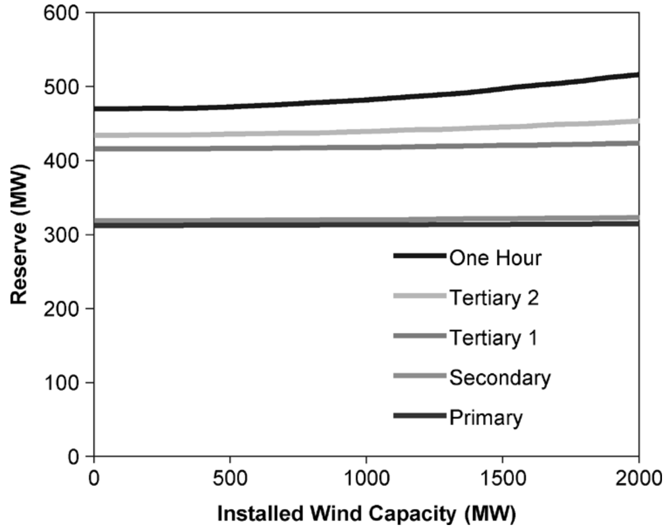

Fig. 10. Conventional reserve categories versus installed wind capacity.

is taken to be 2% of the total system load at any given hour. This amount is deducted from the primary and secondary reserve targets to give the net primary and secondary reserve targets that must be met by conventional generation. Fig. 10 shows how much of each category of reserve is needed at the start of a one hour period (i.e., one hour forecast horizon) to operate with a LSI of 3 per year.

Increasing wind penetration has little effect on the categories of reserve that operate over a shorter time frame, this is due to the small standard deviation of the forecast errors over such short periods. It should be noted that the reserve targets shown in Fig. 10 are the amounts of each category of reserve that need to be in place at the start of that hour to operate in accordance with the reliability criterion. If the reserve has to be put in place some time before the start of that hour, i.e., a forecast horizon greater than one hour, then more reserve will be needed to cover for the possible total system variation between the time the operating decisions were made and the start of the hour period (see Fig. 8).

With wind power capacity causing the largest increases in reserve categories which act over longer time frames, it is beneficial for a system to have a high proportion of fast starting plant which can provide this reserve at low cost.

V. Conclusion

This paper presents a new probabilistic approach to calculating system reserve that accounts for the uncertain nature of wind power production. The approach links the amount of reserve carried on the system in any hour with the reliability of the system over the year. The technique is applied to a model of the all Ireland system, and it was shown that increasing wind power capacity causes a distinct but not excessive increase in the amount of reserve needed on the system. Due to the small nature of the total wind power variations over short time frames the impact of wind power capacity on the more expensive fast acting reserve categories is minimal. Increasing amounts of wind capacity causes a greater increase in the need for categories of reserve that act over longer periods of time. It is shown that committing reserve with a large forecast horizon, i.e., several hours before the hour in question, causes an increase in the amount of reserve needed, as extra reserve must be committed to cater for possible wind power deficits between the time the operating decisions were made and the period in question.

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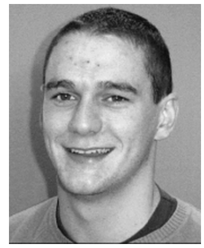

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