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Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power

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ABSTRACT

The variability inherent in wind power production will require increased flexibility in the power system, when a significant amount of load is covered with wind power. Standard deviation (σ) of variability in load and net load (load net of wind) has been used when estimating the effect of wind power on the short term reserves of the power system. This method is straightforward and easy to use when data on wind power and load exist. In this paper, the use of standard deviation as a measure of reserve requirement is studied. The confidence level given by $\pm 3-6$ times σ is compared to other means of deriving the extra reserve requirements over different operating time scales. Also taking into account the total variability of load and wind generation and only the unpredicted part of the variability of load and wind is compared. Using an exceedence level can provide an alternative approach to confidence level by standard deviation that provides the same level of risk. The results from US indicate that the number of σ that result in 99% exceedence in load following time scale is between 2.3-2.5 and the number of σ for 99.7% exceedence is 3.4. For regulation time scale the number of σ for 99.7 % exceedence is 5.6. The results from the Nordic countries indicate that the number of σ should be increased by 67-100% if better load predictability is taken into account (combining wind variability with load forecast errors).

1. INTRODUCTION

Integration of wind power in large electrical power systems is primarily the subject of theoretical studies, as actual wind power penetration levels are still modest. Integrating wind power in power systems means taking into account the time varying patterns of wind power production while scheduling the generation and reserve units in the power system. Integration costs are the costs incurred when incorporating the electricity from wind generation into a real-time electricity supply, ensuring reliability in system operation. These will include costs for allocating and using more short term reserves and decreased efficiency in conventional power plants due to variability of wind. This can also include costs from grid reinforcement and extension depending on where the wind resource is located.

In this paper, the allocation and use of short term reserve, on the time scales of minutes to tens of minutes are the focal points. Wind power production is characterised by variations on all time scales: seconds, minutes, hours, days, months and years. Even the short term variations are to some extent unpredictable. Large geographical spreading of installed wind power will reduce the variability and increase the predictability of the aggregate wind power production.

To estimate the impact of wind power on power system operational reserves, it has to be studied on a balancing area basis. Every change in wind output does not need to be matched one-for-one by a change in another generating unit moving in the opposite direction. Rather, it is the total system aggregation of the variations in all loads and generators that has to be balanced. The relative increase in system fluctuations due to wind power depends on the wind penetration level – what portion of consumption is covered by wind power production. Also, each system is different: the levels of load variability, as well as the flexibility in the system, differ from region to region and from country to country. This means that even for systems with the same wind penetration level there will be different wind integration costs.

A widely used method for estimating the incremental increase of variability that the power system must balance when adding wind power is the consideration of the difference between the distribution of variations before and after wind power. As an estimate of the increase in variability, the standard deviation (σ) of the distribution can be used as a confidence level. Even if this is not the method by which the operating reserves are allocated in real power systems, this method is fairly easy to use and produces a value that is related to the degree by which wind power increases the variability in the power system (Kirby and Hirst, 2000). However, there is not a consensus on what is the ideal value of the confidence level, that is, should ± 2.3 times σ or ± 6 times σ be used (Holtinen, 2004; GE Energy, 2007; Dragoon & Milligan, 2003; Milligan, 2003; Enernex, 2006; Enernex, 2007; Idaho Power Corp., 2007). How large this confidence level should be is the issue for this paper. This paper will also examine different time scales and different implications of applying sigma, also looking at different times of year/variable reserve.

2. POWER SYSTEM RESERVES

The failure to keep an electric system running has serious and costly consequences, thus the reliability of the system has to be kept at a very high level. Reliability and security of supply need to be maintained for both the short and long term. This means maintaining both the flexibility and reserves necessary to keep the system operating under a range of conditions, including peak load situations. These conditions include possible unscheduled plant outages, as well as predictable and uncertain variations in load and in primary generation resources including wind. Real time load following is accomplished with operational reserves, while day ahead scheduling for unit commitment is done according to the load/wind forecast.

2.1 Reserve Categories

Reserves can be divided into different categories according to the time scale within which they are operating. There are different practices and terminology in different power systems, but generally speaking there is first an instantaneous reserve that is maintained in power plants operating on-line and is activated automatically to correct for frequency fluctuations. Then there is a second reserve that is activated 10 to 15 minutes after the occurrence of frequency deviation from nominal frequency. It replaces the instantaneous reserve. This reserve consists mostly of rapidly starting gas turbine power plants, hydro (pump) storage plants, unloaded generation already online, and load shedding can also be used.

There is wide agreement on the type of reserves that must be carried and the time frames that are relevant, but there is no universal agreement on nomenclature. For this paper we adopt the following terminology:

- Contingency reserve (also called disturbance reserve): capacity that is online and synchronized to guard against unforeseen equipment failure. The amount of

contingency reserve is typically based on the largest potential source of failure, either the largest generator or tie line in the system. Contingency reserve is held independently of the variability of loads, and is typically shared among participants within the balancing area, reducing the overall contingency requirements for the individual entities. Some portion of the contingency reserve can be non-spinning, but must be capable of responding quickly if needed.

- **Regulating reserve** (also called response, instantaneous/momentary reserve, primary reserve): fast fluctuations in system load require fast generation response. Regulation consists of flexible generation that is connected to automatic generation control (AGC) systems. The AGC will send control signals to the participating regulating units as needed so that the aggregate load is balanced with generation. Units that provide regulating reserve are usually run near the mid-point of the operating range. When a regulating unit is required to deviate from that preferred operating point for a longer period of time, adjustments are made to the units on economic dispatch so that the regulating unit can return to its mid-point operating setting.
- **Load-following reserve** (also called secondary/tertiary reserve, minute reserve): This consists of generation that may be called on to increase or decrease output over slower time frames than regulating units. The units that are available for load following must be committed in advance, or capable of quickly starting and synchronizing with the grid, typically within 10 minutes. Depending on the resource mix that is available to the power system operator, load-following reserve can be either spinning or non-spinning, or as is most common, will be a combination of both. Slow-start generation must be committed prior to becoming available for dispatch or to supply reserves.
- **Planning reserve** (also called long-term reserve): This type of reserve covers not only operating requirements, but recognizes that not all of the installed capacity may be available when needed. Planning reserve is usually found to be in the range of 12-20% of peak load, depending on the system and the planning criteria in use at the locale in question.

Although wind power plants can at times create large “ramps” (i.e. large swings in production level), at current wind penetrations in most parts of the world these are not big enough or fast enough to be considered contingency events (Milligan & Kirby, 2007; GE et al, 2007). The planning horizon is longer than what we consider herein. That leaves us with two categories of reserve to analyze in this paper: regulating reserve and load-following reserve.

It is fairly straightforward to determine contingency reserve required because the largest contingency is a known specific event. Regulating and load following reserve performance is more difficult to specify. It is not practical and it is not necessary for any single balancing area within an interconnection to continuously perfectly match generation and load. For example the Control Performance Standard 1 (CPS1) in US recognizes this and places an annual statistical limit on the one-minute product of balancing area imbalance and system frequency deviation. Note that this is a performance metric, not reserve requirement. A balancing authority must have “enough” reserves to meet the statistical performance standards, however much that is.

2.2 Electricity Markets

In the liberalised electricity markets the scheduling and dispatch of the power plants (unit commitment and load following according to load forecasts) can be dealt with in the day-ahead

market and real-time energy markets, as well as through bilateral contracts between the participants. In the event of major frequency deviation, the transmission system operator (TSO) adjusts the production or the consumption manually, using reserves activated in 5-15 minutes. This can be done through a common balancing power market (e.g. Nordic countries and some parts of the U.S.), where the players submit their bids for upward and downward regulation of production or consumption. Contracts between some producers (and consumers) and system operators can also be made to allocate the reserves.

When system operators operate sub-hourly (intra-hourly) energy markets which clear every five, ten, or fifteen minutes, this will provide much of the system load-following requirements without the need for an explicit load-following reserve or balancing market. Regions that only have hourly markets must use load following reserve or balancing market to cover more of the sub-hourly movements of (aggregate) load and wind.

Random, minute-to-minute real-power fluctuations and contingencies (the sudden unexpected failure of a large generator) must be compensated for immediately and happen too quickly for energy markets to respond. Regulating reserve and contingency reserve can be obtained from hourly markets which operate in parallel with the energy markets. In actual operation the system operator will use any available energy market response along with contingency reserve to deal with an actual contingency. However, in most systems there are reliability rules that govern each balancing area requiring contingency reserve capacity to be purchased and made available in order to assure adequate reserve availability and system reliability. Energy market opportunity costs dominate regulation market and contingency reserve prices but reductions in generator efficiency when regulating are important as well.

3. IMPACT OF WIND POWER ON POWER SYSTEM RESERVES

When wind power is introduced to the power system, the additional requirements and costs of balancing the system in the operational time-scale (from several minutes to several hours) are primarily driven by fluctuations in wind generation output. Wind power production can be predicted 2-40 hours ahead. The varying production patterns of wind generation changes the scheduling and unit commitment of the other production plants and use of transmission between regions – either losses or benefits are introduced to the system, compared with the situation without wind. Depending on the prediction accuracy, parts of the production variations remain unpredicted or are predicted incorrectly, and there will also remain subhourly changes in output. This is what has to be handled by load following reserve or the balancing market. Even if there is an accessible balancing market, it is still necessary to ensure that there is enough capacity bidding to the market (depth of balancing market, stack) to cover the increased reserves.

There are means to reduce the variability of wind power production. Staggered starts and stops from full power as well as reduced (positive) ramp rates can reduce the most extreme fluctuations, in both magnitude and frequency, over short time scales (Kristofferson et al, 2002). This reduction is at the expense of production losses, so any frequent use of these options should be weighed against other measures (in other production units) in cost effectiveness (GE et al, 2007).

The impact that wind energy has on power system reserves will depend on several factors, including the physical impact that wind has on system variability, the ability of the system operator to predict system behaviour over the load-following time scale, and the time-scale itself. The relevant time scale for the reserve requirements is from a few minutes to an hour. For regulation, the time scale is from seconds to minutes (1-10 min in US). The time scale for

load following is 10–60 minutes. For wind power, prediction errors 2–36 hours ahead can also affect the operating reserve. However, there are means to reduce the prediction errors as more accurate forecasts come available closer to the delivery hour.

For frequency control (regulation and load following for intra-hour variability), the synchronously operated system that does not have bottlenecks of transmission forms a relevant area. The relevant area for reserve allocation can be a large interconnected area, however, it has to be taken into account that aggregation benefits exist when there are no bottlenecks of transmission (congestion) between the areas. Large control areas experience more load diversity than small ones, and have a larger resource stack that can be committed and dispatched to meet the load. A small isolated control area has limited ability to respond to fast ramp events because of its limited resource stack.

The manoeuvrability of available generation resources that exists in any given hour depends on the previous unit commitment decision. This may result in a problem with discrete generator step sizes problem: over some hours there may be no need for additional reserves because either there is little wind or because variations in load net wind can be handled by already-committed resources.

In addition to correcting for forecast errors, there are ramping requirements to follow the sub-hourly movement of (aggregate) load and wind, especially if scheduling is based on hourly blocks. It is therefore common to separate the impact of wind into two categories: those impacts that arise because of wind's natural variability (in the short term, inside an hour), and those impacts that are caused by wind's uncertainty (prediction errors).

The size of the control area, or balancing area as they are called in the U.S., can have a significant impact on its ability to absorb large wind penetrations and to reduce the physical requirements for system balance. Over short time scales in the regulating time frame, load is generally uncorrelated, which implies that regulating reserve requirements benefit from aggregating many individual loads from larger area. As the time scale becomes longer, approaching an hour or more, there is more correlation in load movements; hence the prominent morning load pickup and evening load drop-off periods are significant as most loads move together. Wind exhibits similar characteristics. Over a period of seconds to minutes, wind turbines see different wind speeds, so the turbine output tends to be uncorrelated. Over longer periods, there can be more correlation such as periods of time when weather fronts pass thru the wind plant. As the geographic area covered by loads and wind turbines increases, the shorter correlations remain small, which results in diversity benefits of large balancing areas. Milligan and Kirby (2007) analyze the impact of larger balancing areas on wind integration, and find that generator ramping requirements can be reduced significantly in large balancing areas, compared to small ones.

4. OVERVIEW OF METHODS TO CALCULATE WIND'S IMPACT ON RESERVES

4.1 The Statistical Approach Based on Sigma (Standard Deviation)

We approach the reserve issue by noting that the system operator must balance the aggregate loads and generation. We can then study the variability of load and wind power with time series of variations of wind power (P) and load (L):

$$\Delta P_i = P_i - P_{i-1} \quad (1)$$

$$\Delta L_i = L_i - L_{i-1}, \quad (2)$$

where i denotes the hour (from 2–8760 in one non-leap year). The increase of variability that wind power brings to the power system can be seen when comparing their combination (net

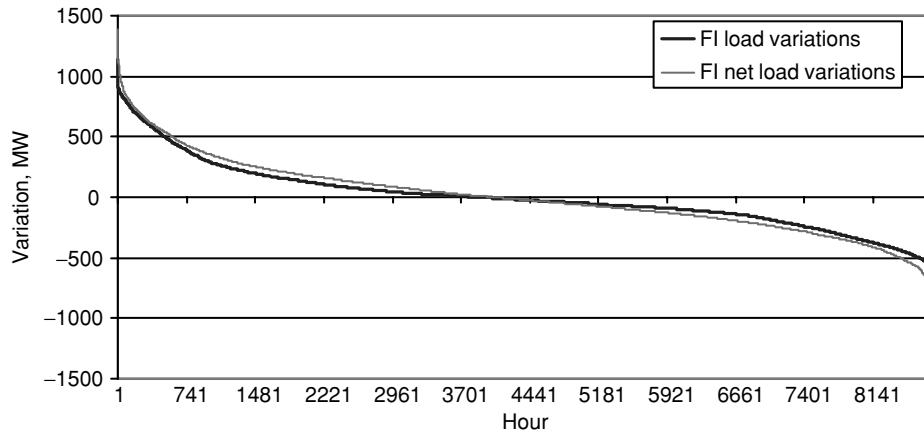


Figure 1: Duration curves of annual load variations without wind power and net load variations with wind power. The case is for Finland in the year 2000 with hypothetical 6000 MW wind (17% of gross demand). Source: Holttinen, 2004.

load) with the original load time series. Net load is the load minus the wind power production for each hour. The net load hourly variations are calculated like the hourly variations (1), but now for the net load time series (NL), where wind power production is subtracted from load:

$$\Delta NL_t = NL_t - NL_{t-1} = (L_t - P_t) - (L_{t-1} - P_{t-1}) = \Delta L_t - \Delta P_t \quad (3)$$

In Figure 1, the amount of hourly variations that the system sees is depicted showing one year of data in decreasing order (duration curve). There are two curves, the load variations without wind and load variations together with wind (the hourly variations of net load). The difference in the maximum values of MW of variations with and without wind indicates the amount that the operating reserve capacity must be increased. The difference in overall MW variations shown in the duration curves indicates the increased amount of existing reserve capacity operating, when wind power is added. The same capacity can in principle be used for both up and down regulation, and the variations as well as the increase should essentially be symmetrical. Either up or down (positive or negative) variations can determine a need for an increase in the reserves.

Planning and operating a power system is based on probabilities and risk. Reserves in the power system - with or without wind power - are generally determined so that variability within a certain probability are covered, for example 99.99 % of the variability.

Standard deviation σ tells about the variability of the time series, it is the average deviation from mean value μ :

$$\sigma = \sqrt{\frac{\sum_{i=1}^n (x_i - \mu)^2}{n}} \quad (4)$$

For a normally distributed probability distribution, the standard deviation σ is a measure indicating that about 68 % of the data is inside $\pm\sigma$ of the mean value. Taking a range of $\pm 3\sigma$ will cover 99 %, and $\pm 4\sigma$ will cover 99.99 % of all variability. For hourly variations, the mean value is 0 by definition.

If the variability of load and wind power production can be assumed to be uncorrelated, the standard deviation of net load time series (σ_{NL}) can be determined by a simple square root sum of the standard deviations of load (σ_L) and wind power (σ_W) time series:

$$\sigma_{NL} = \sqrt{\sigma_L^2 + \sigma_W^2} \quad (5)$$

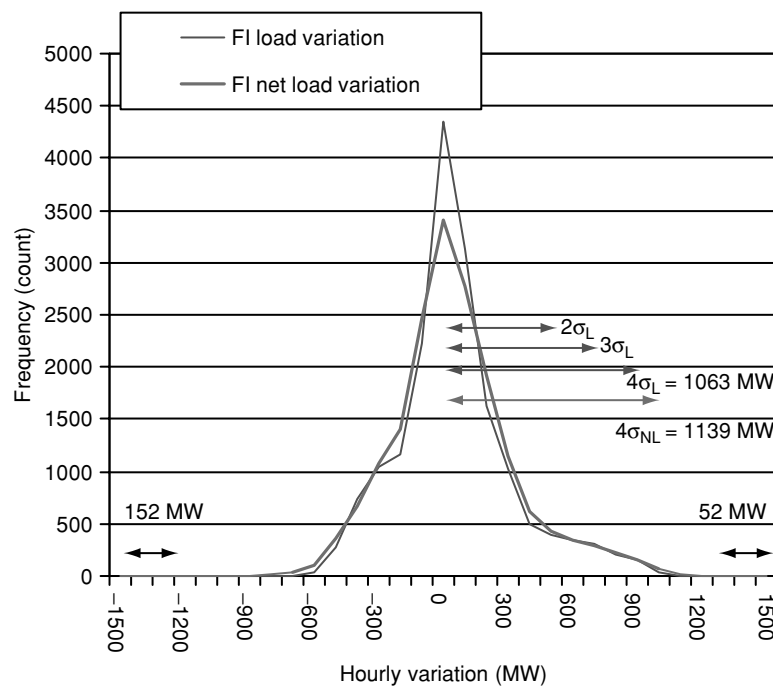


Figure 2: An example of estimating the increase in hourly variability seen by the system (Holttinen, 2005, Finland 2000–2001 data). If only maximum variation is looked at, the increase is determined at the tails of the distribution (52 MW increase in positive up-variation and 152 MW increase in negative down-variation). Looking at the standard deviation of the distributions, there is a difference of 76 MW in the 4σ coverage of the variability (1139–1063 MW).

The hourly variability of wind power production and load do experience some correlation in the data of some regions. Also, the distribution of the variations is not usually strictly a normal distribution. However, formula (5) has been checked for several sets of data and it has produced accurate results for the standard deviation of the net load (Holttinen, 2005).

Finally, the increase in the variability due to the wind can be formulated as the increase in some multiple of σ , calculating the increase from σ_L to σ_{NL} using for example 4σ as the confidence level covering most of the variability:

$$I = 4(\sigma_{NL} - \sigma_L) \quad (6)$$

In Figure 2 the distribution curves for the variations in load and net load are depicted, showing also how far 2σ , 3σ and 4σ reach to cover the variability of the dataset.

4.2 The Statistical Approach Based on Exceedence Level

A related approach to calculating load following reserve requirements for wind is to work the previous example backwards. Instead of calculating some multiple of σ , which corresponds to a given (low) probability that load will exceed generation, the probability level is chosen based on *a priori* risk tolerance. For example, if the chosen exceedence level is 99%, then the load (or load less wind) can be sorted and the entry for the 99th percentile can be extracted. In a normal distribution, this would correspond to 3σ . However, if the underlying distribution is not normal, using an exceedence level can provide an alternative approach that provides the same level of risk.

To examine the reserve impact of wind, this approach can be easily done by (1) calculating a given exceedence level (percentile) for load alone, (2) calculate the same exceedence level (percentile) for the load net wind, and (3) comparing the incremental capacity of the two calculations. An example from Minnesota in the United States will be shown in a later section of this paper.

5. APPLYING SIGMA METHOD TO DIFFERENT TIME SCALES AND TIME SERIES

5.1 Time Scales of Regulation and Load Following

Regulating reserve must be available through the automatic generation control (AGC) scheme and responds over time periods of up to several minutes. It is not uncommon for the system operator to carry regulating reserves equal to $\pm 5\sigma$ or $\pm 6\sigma$, where σ is the system variability measured as standard deviation of the load variability.

However, over longer time scales it may be possible to obtain generator responses from other sources, including non-AGC units that are spinning and synchronized, market participants, or quick-start generation that is not spinning. In systems with significant run-of-river hydro, the overall system variability will also be a function of the hydro variability over the time scale of 10–60 minutes, in addition to load and wind forecast errors and sub-hourly ramping. Some recent studies in the United States, for example (EnerNex, 2006; EnerNex, 2007 and Idaho Power, 2007) have used $\pm 2\sigma$ as the preferred metric to calculate load following requirements for wind. This is based on the requirement (imposed by the North American Electricity Reliability Corporation, NERC) that the minimum required score for control performance standard 2 (CPS2) is 90%, which approximately corresponds to the normal probability value for 2σ . Other U.S. studies have used $\pm 3\sigma$ as the appropriate confidence interval (GE Energy, 2007; Dagoon & Milligan, 2003; Milligan, 2003). A recent study undertaken by GE Energy of the Ontario system used $\pm 3\sigma$ and used a corresponding exceedence analysis as a supplement (GE, 2006).

As more data and other methods for reserve requirement estimation emerge, it is interesting to see how well the general assumptions of multiples of sigma used so far in the studies reflect the increase in reserve requirement needs due to wind power.

5.2 Applying Sigma Method to Load Forecast or Load Variation Time Series

Regulation and load following reserves are used as balancing services required after generators have moved to follow energy price signals. Clearly, there is more residual left if only hourly energy markets are available and less if there are five minute energy markets. The physical power system sets energy market prices in order to move generators' output based on a short term forecast of expected load movements. The desire is to move the economic units (units being dispatched to provide energy based on their cost or price) to the centre of the expected load range and to simultaneously move the regulating units to the centre of their response range. This positions them best to be able to respond to the next random load movement.

When modelling the power system it would be best to either record the short term load forecasts or to have sufficient information to enable creation of a short term load forecast to position the economic generators. This is difficult because it involves either recording a great deal of forecast data that most system operators do not currently record or it requires duplicating their sophisticated load forecasting tools and having access to the large amount of data that they themselves require.

If the forecasts are not available, an analysis technique provides a simple but excellent proxy for short term forecasts. A rolling average of the load time-series can be used as a

forecast for the load-following component. This works (and is a good approximation of reality) because short term load forecasts themselves are typically quite accurate. The correct rolling average duration depends on the type of short-term energy market that is available. If only hourly markets are available then a 60 minute rolling average is appropriate. If a five minute energy market is operating then a five minute rolling average is appropriate (Kirby & Hirst, 2000; Kirby & Hirst, 2001). It turns out that in practice with real power systems the *exact* rolling average time interval is not important but the range is: there is little difference between five and ten minute rolling averages but a large difference between five and sixty minute rolling averages. In any event, using a rolling average to separate regulation from load-following captures the full variability of the load. The technique simply segregates that total variability into the two categories.

5.3 Wind Data

It is important to look at the representation of the wind data to describe the hourly variability of large scale wind power production. The data needs to be upscaled to look for the future impacts of large scale wind power. If too few time series of wind power plants are used, upscaling the time series will also upscale the hourly variations, not taking into account the smoothing effect of thousands of turbines at hundreds of sites. At some stage the smoothing effect will saturate: adding more turbines/sites will not result in less variability (Holttinen et al, 2007).

Large scale wind power production varies less the smaller the time step considered (Ernst, 1999). The results from a study for Northern Ireland suggest that at a 10% penetration, the increase in hourly variability in the net load (load - wind power) is less than 2% of wind power capacity, whereas the half-hourly data gives an increase of less than 1% of wind power capacity (Persaud et al., 2000).

5.4 Varying Reserve Requirements Throughout The Year

When wind is generating a small fraction of its rated output, it makes little sense to hold up-capable load following reserves that would guard against a drop in wind of the same magnitude as its rated output. Likewise, when wind generation is near maximum output, downward load following ability will depend on load levels, not wind. Figure 3 is taken from (Krich & Milligan, 2005) and shows the incremental variability that wind adds to load in the hourly time frame. The graphs separate a geographically disperse case (installed capacity divided to three sites with equal amounts of wind power) from a non-dispersed case (same amount of MW's all at one site), and show various seasons, months and hours. It is clear from the figure that incremental reserves that are induced by wind would not be constant throughout the year. At least one recent integration study in the United States has explicitly calculated this variable reserve, and will be discussed later in this paper in section of case Minnesota.

5.5 Allocation Methods

The incremental increase in reserve requirement due to wind power is often used as the reserve requirement for wind power. Instead of allocating the simple addition to wind power it is also possible to take the total reserve requirement and allocate that to both wind and loads by alternative means. Selecting a variability allocation method is not exclusively a technical matter. Individual load and/or generator variability is usually not highly correlated with the variability of other loads and/or generators. When multiple individuals are aggregated together the variability of the total is less than the sum of the variability of the individuals.

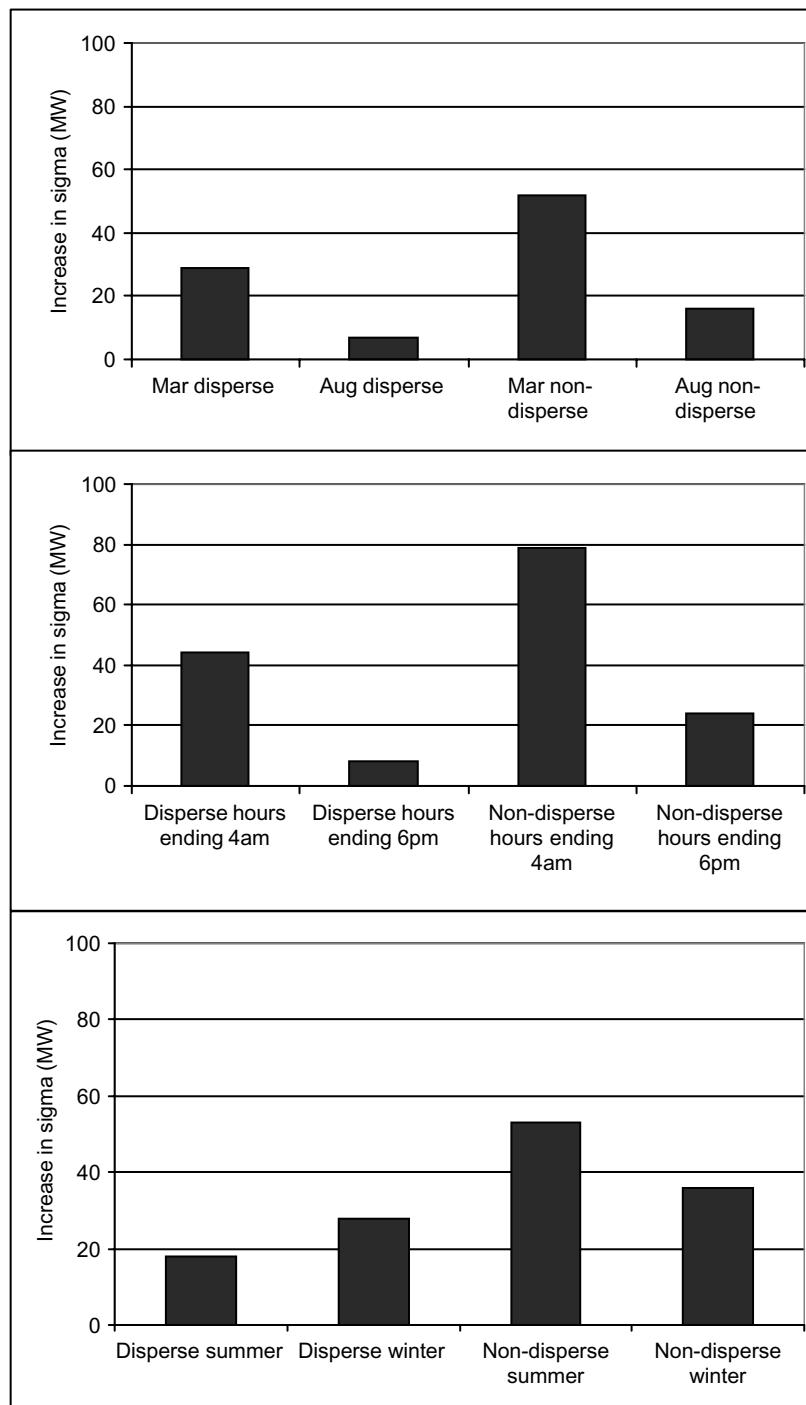


Figure 3: Incremental variability from wind varies by time of year and time of day.

When two utilities with equal regulation requirements combine the new entity requires only 1.4 times the regulation that one individual required, not twice the regulation. Should both share the savings with each being allocated 70% of the original requirement? Or should one pay the full 40% incremental regulation cost when it joins the second? The second is not harmed by the joining of the first but if the entities are “equals” like in the example of two utilities, the incremental method does not seem fair. Alternatively, a regulator might adopt the incremental regulation allocation method if a new entity provided significant societal benefits

such as job creation (steel mills) or environmental benefits (wind generators). The rest of the system would see no increase in regulation cost and the industrial plant or wind generator would be interconnected at minimal cost.

Variability can be allocated based upon causation while accounting for the nonlinearity (Kirby and Hirst, 2000). The allocation methodology is independent of the order in which entities are added to the aggregation and independent of how many or few pieces the total is split into. Individual variabilities can exhibit any amount of correlation. The total allocated variability always equals the total system variability. Figure 3 illustrates the allocation method graphically when two entities (A and B) are combined. It is the correlation of the individual with the total requirement that determines the allocation.

Numerical implementation of the allocation method, shown in equation 7, is straightforward and can be done for as many or as few individual generators and loads as desired. The allocated variability is then multiplied by the same factor that total variability was multiplied by to determine the reserve requirement in MW.

$$Allocation_A = (\sigma_{Total}^2 + \sigma_A^2 - \sigma_{Total-A}^2) / (2\sigma_{Total}) \quad (7)$$

Using this allocation method will increase the integration cost estimate for wind power. In most power systems, different loads and production units do not pay different tariffs for the regulation burden they pose to the system. As a result, some nonconforming loads which impose much higher than average regulation burdens on the power system, pay for far less regulation than they should. To date individual load allocation has not been implemented in a tariff. Until the reserve requirements are allocated to individual loads and production units, it is well justified by wind integration studies to calculate only the simple addition to reserve requirements. Both methods result in full cost recovery for the utility.

6. CASE: MINNESOTA, US

In 2005 the Minnesota (US) legislature directed the Public Utilities Commission to analyse the impact of a 20% renewable portfolio standard in the state. Under the assumption that most of this renewable generation would come from wind, the PUC retained EnerNex Corp, who with WindLogics, developed detailed chronological wind generation estimates and simulated the Minnesota grid to determine the impact, and ultimately, the integration cost of wind.

6.1 Comparison of Exceedence Level and Sigma Approaches

To provide a simple analysis of the relationship between the sigma approach and a statistical-exceedence method, we obtained the hourly data from the study and analyzed it for this paper. Figure 4 shows the data in graphical form.

Using this data we calculated the exceedence level at 99% for load, and for load with wind. The basis of the calculation was to investigate the 99th percentile of the variations in load compared to load - wind. We then compared this with a 3 σ rule. The results appear in Figure 5.

The results indicate that the number of sigmas that result in 99% exceedence is between 2.3-2.5, as indicated in Figure 6. The data in this discussion is taken from a 25% (energy) wind penetration. The 3-sigma rule results in a very high reserve margin in the load following time scale, 31-40% of wind rated capacity for a 2-sigma and 3-sigma rule, respectively. The 99th percentile exceedence rule results in a 31% reserve. This is clearly much higher than other results in this paper.

There are a few clarifying points that should be made. The reserve calculation in the integration study from which the data was obtained utilized a variable reserve method that

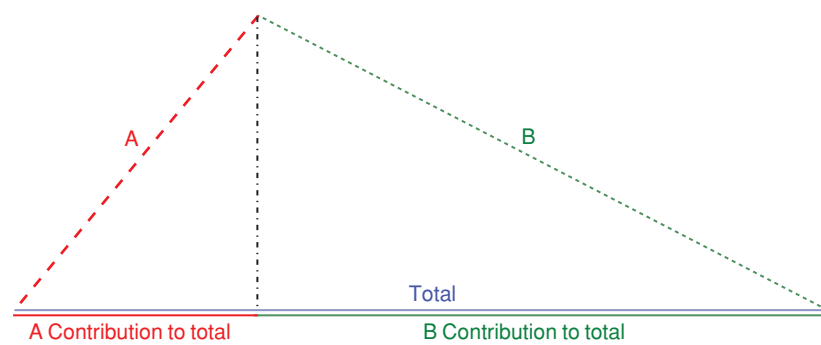


Figure 4: Individual variability is allocated based upon correlation with total system variability.

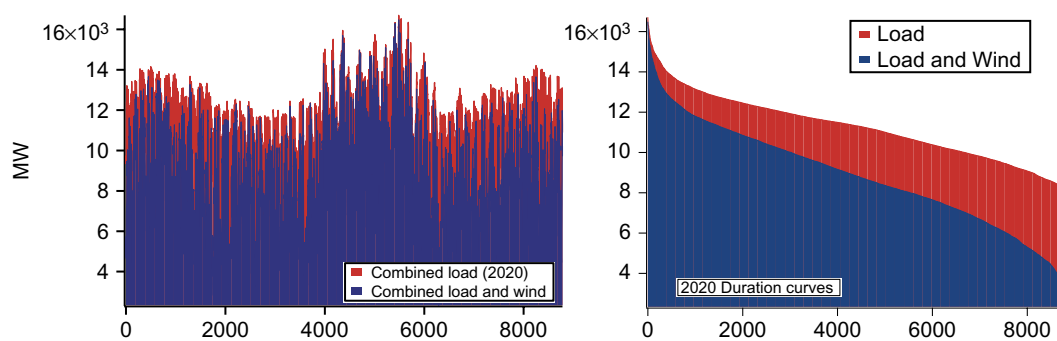


Figure 5: Minnesota load and wind data. 5689 MW rated capacity of wind and peak load of 16,698 MW. The hourly load and net load (load - wind) are presented as time series (left) and as duration curves (right).

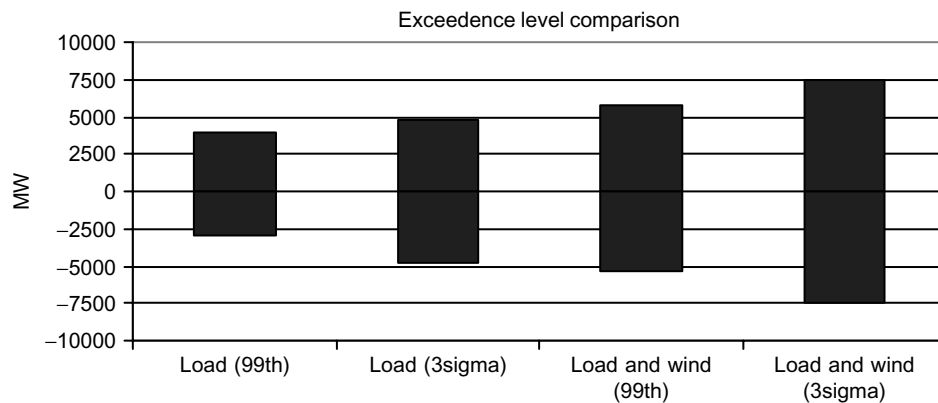


Figure 6: Comparison of 99% exceedence rule with 3σ shows that 3σ more than covers 99% of variations (5689 MW rated capacity of wind and peak load of 16,698).

reduces the overall reserve obligation throughout the year. Furthermore, the load following reserve as calculated in the study was based on dynamically applying a 2-sigma rule, based on the variability of the wind (details provided below). The 99th percentile level corresponds to the 2-sigma level of reserves, indicating a distribution that is not normal.

6.2 Varying Reserve Requirement Through The Year

As a result of in-depth discussions with the technical review committee of the Minnesota Wind study, the production simulation modelling incorporated estimates of wind's standard

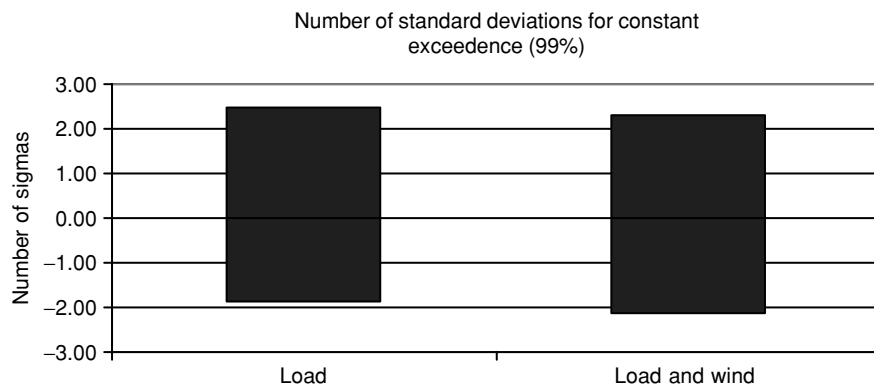


Figure 7: Number of sigmas to achieve the reserve requirement of 99% exceedence level analysis, for up-and down regulation needs.

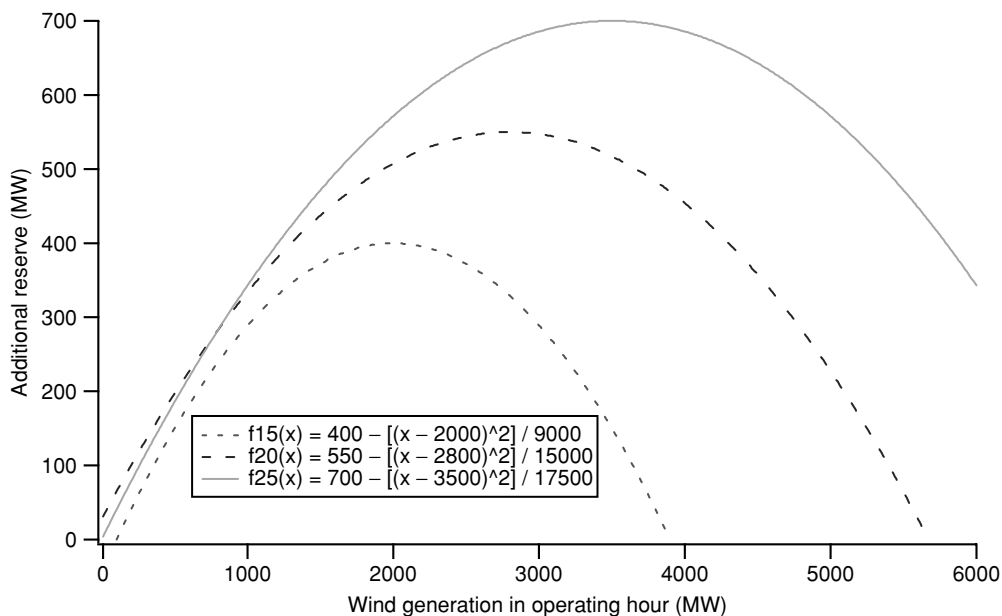


Figure 8: Reserve component based on the standard deviation of net-hour wind generation.

deviation to calculate variable operating reserve. The approach used is a variation of those discussed in prior sections of this paper; instead of calculating a single multiple of sigma, this approach used a dynamic approach that allowed the reserve level to be calculated based on the amount of wind generation that was operating. EnerNex divided the chronological wind generation into quintiles based on generation level, and then calculated the standard deviation within each grouping. Based on the results, a variable operating reserve component based on 2σ of the change in hourly wind generation was added geometrically (as root-sum-squares process) to the production simulation modelling. Dividing the wind generation into quintiles, the standard deviation for each quintile was calculated, and a series of quadratic functions were estimated, one for each penetration level. The quadratic functions are based on fitting the two-sigma changes in wind production for each quintile, Figure 8 shows the quadratic functions and the respective curves for each of the wind penetration levels studied.

Figure 9 illustrates the relationship between the additional reserve imposed by wind and the level of wind generation based on the quadratic formulas, and is adapted from the

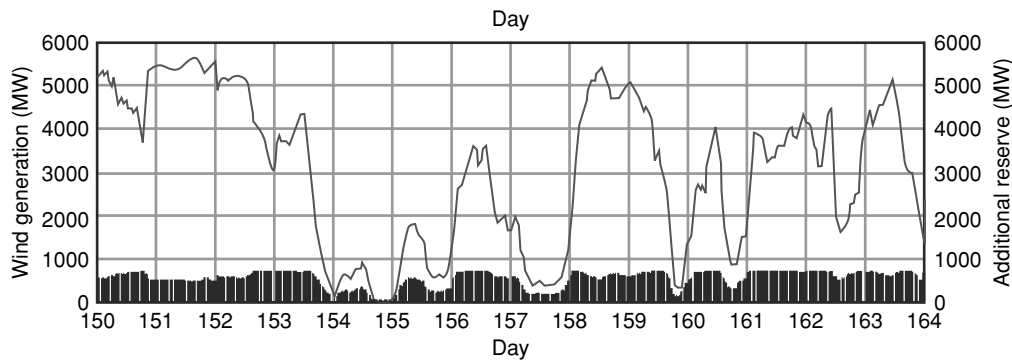


Figure 9: Illustration of variable operating reserve from the Minnesota 20% Wind Study, EnerNex 2006.

Minnesota report. To properly interpret the Figure it is important to note that this reserve level was added geometrically to the other reserve components; therefore the graph overstates wind's impact on overall reserve requirements, which averages 7.6% of the rated capacity of the wind plant. In any given hour, the reserve level could be either higher or lower than this average value.

7. CASE: GRANT COUNTY PUD, US

Beginning in 2005, Public Utility District No. 2 of Grant County (Grant PUD) in Washington State, USA, has been studying the impact of wind energy generation integrated into its balancing area, which is supplied by nearly all hydropower. Grant PUD owns and operates the two-dam Priest Rapids Project on the Columbia River in central Washington. Together, the Wanapum and Priest Rapids Dams have the capacity to produce approximately 1,855 MW of electricity. Grant PUD shares the output of this project with other utilities, with about 850 MW of output used for their own load and sales obligations in 2006, including reserves, with a peak system load of 610 MW. With respect to wind energy, Grant PUD purchased 12 MW of the 63.7 MW Nine Canyon Wind Project, which was expanded to 99.2 MW in 2008. Wind power output from Nine Canyon is integrated via a dynamic signal into Grant PUD's balancing area. In studying wind integration, Grant PUD has sought to understand the impacts and costs of integrating wind and hydropower and the potential for future expansion of wind integration. Refer to Acker, et.al., 2007 for more details of the study.

7.1 Comparison of Exceedence Level and Sigma Approaches

Of importance in determining the impact of wind in their balancing area, Grant PUD has carefully considered different methods of computing the regulation and load following requirements on their system, due to their system load and the influence of wind variability. Two basic methods were considered: 1) Determine the distributions for hourly (load following) changes and minute-to-minute (regulation) changes, then multiply the standard deviation of these changes by some number (between three to five) to assess the load following and regulation requirements; and 2) Create exceedence curves for both the load following and regulation changes, and find the "99.7%" point on these curves, which will then define the load following and regulation values. Note, for a true normal distribution, 99.7% of all occurrences should occur within ± 2.96 (approximately 3) standard deviations of the mean. Ultimately, Grant PUD decided that the 99.7% exceedence method is the preferred method of calculating these load following and regulation values.

Table 1. Grant PUD results for standard deviation and exceedence value methods of computing the load following and regulation requirements, for 63.7 MW of wind power, 2006 data. Multiples of sigma indicate reserve requirement estimation from exceedence value results: 5.5–5.6 times sigma for regulation time scale and 3.3–3.4 times sigma for load following time scale.

	Standard Deviation		99.7% Exceedence Value		Multiples of Std. Dev.	
	Regulation (MW)	Load Following (MW)	Regulation (MW)	Load Following (MW)	Regulation (MW)	Load Following (MW)
System load only	2.09	12.09	11.68	39.86	5.59	3.30
System load net 63.7 MW wind	2.11	12.90	11.74	43.86	5.56	3.40
Increase due to wind	0.02	0.81	0.06	4.00		

In computing the regulation and load following changes, a 10-minute rolling average of the system load was created. The 1-minute regulation values were then computed by taking the difference between the actual 1-minute system load and the 10-minute rolling average for data from the first eleven months of 2006 (about 481,000 1-minute values; the twelfth month was not available at the time of the analysis). The load following was computed by taking the signed difference between the maximum and minimum value of the 10-minute rolling average during each hour in the data set (about 8,000 1-hour changes). Other methods were considered for defining the regulation and load following, such as using a 60-minute rolling average, but all yielded similar results for the comparison to be made here.

Figure 10 shows a histogram of the regulation (1-minute) changes and its associated exceedence curve. In creating the histogram and exceedence curves, Grant PUD's 1-minute system load was analyzed without wind (corresponding to 0 MW of wind) and netted (system request minus wind power production) with 12, 63.7, and 150 MW of wind (1-minute generation values). The actual output of the 63.7 MW Nine Canyon project was used in making these calculations, and directly scaled to either 12 MW or 150 MW, which in both cases will distort the actual variability of the wind output. For that reason, only the numerical results for the 63.7 MW case will be presented here (note that the system was actually run with 12 MW, and the 63.7 MW is a hypothetical case).

A summary of the results for the regulation and load following calculations are given in Table 1, for the case of 63.7 MW of wind. This corresponds to a wind penetration level of 10.4%, based upon peak capacity (63.7 MW of wind divided by a peak system load in 2006 of 610 MW). The "Standard Deviation" and "99.7% Exceedence" columns shown in this table provide the results for system load only (no wind), for the system load netted with 63.7 MW of wind, and the difference between the two. Shown in the "Multiples of Std. Dev." column is the number of times it is necessary to multiply the standard deviation value to obtain the associated 99.7% exceedence value. As is demonstrated in these results, in order to obtain the exceedence value, it is necessary to multiply the standard deviation values by about 5.6 to obtain the regulation as determined by the exceedence value, and by about 3.4 to obtain the load following as determined by the exceedence value. Note the number of multiples of standard deviations is rather insensitive to whether or not the wind is included.

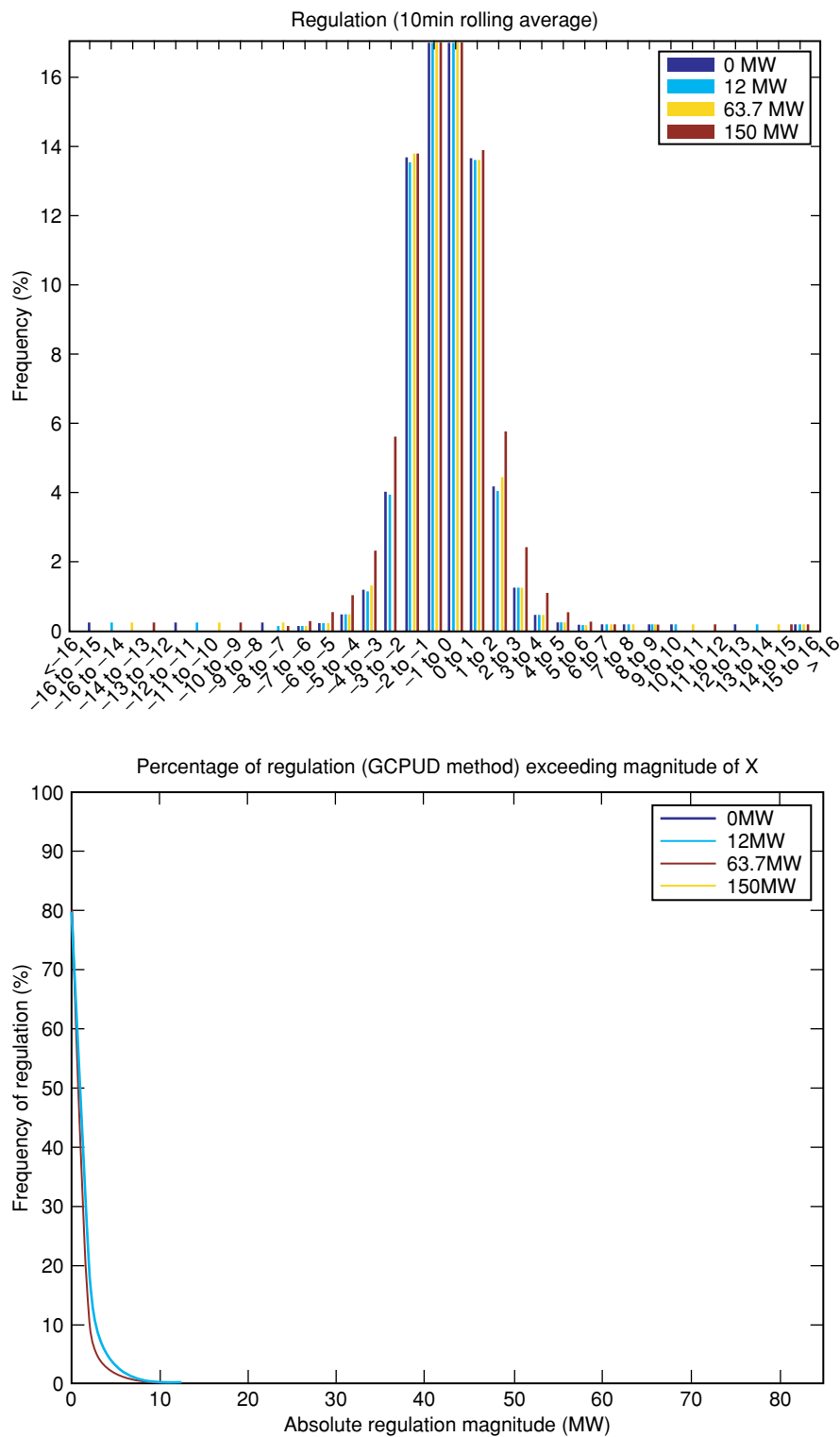


Figure 10: Regulation histogram (top) and exceedence curves (bottom) for Grant PUD 2006 system load considering 0, 12, 63.7, and 150 MW of wind capacity.

8. CASE: FINLAND AND NORDEL

Hourly wind power production time series from 4 Nordic countries were collected for a PhD study on impacts of wind power on the Nordic power system (Holttinen, 2004). Data for hourly wind power production was available from 21 sites in Finland, 6 sites in Sweden, 6-12 sites in Norway and the aggregated total production of hundreds of sites in Denmark West and East. A Nordic data set was formed from the data sets of the 4 countries: Denmark, Sweden, Norway and Finland. The total electricity consumption from the countries, also as hourly time series, was obtained from the same period as wind power production data: years 2000 to 2002. Data is analysed in more detail and the data handling procedure for wind power time series is described in more detail in (Holttinen, 2005). The Nordic wind power production time series was made in two ways: a simple average of the percentage of capacity production of the 4 countries and a more concentrated dataset "Nordic 2010" where half of the wind power capacity is in Denmark.

8.1 Comparing the Sigma Approach with Forecast Data

Simple analysis based on the increase in 4σ variability assumes that the hourly variations of both load and wind power production are unexpected. However, as the load with its clear diurnal pattern is easier to forecast than wind power production, this should be taken into account when analysing the increase in operating reserve requirement due to wind power (Milligan, 2003).

For wind power, the production an hour ahead can be reasonably well forecasted by persistence, that is, taking the production level at hour $i-1$ for the predicted value at hour i . This actually results in using the hourly variation as used in previous sections as a measure of forecast error of wind power production. Short term prediction tools can improve this to some extent, taking into account the forecasted trend of wind speeds in the area, as well as time series techniques that are proven to work quite well for some hours ahead (Giebel et al, 2003). The persistence method therefore produces a conservative estimate for hour-ahead wind power production.

In a case study for Finland, year 2001 load data was carried out to estimate load forecasts. A model at VTT Technical Research Centre of Finland was used, based on calendar days of loads (from year 2000 data) and temperature (Koreneff et al, 1998 and 2000). The mean absolute error, hour ahead, was 0.7 % of peak load. The forecast error for the load was then compared to wind power variations. The standard deviation of forecast error was 123 MW (1% of peak load). This compares with 267 MW for the load hourly variations, so this method assumes that about half of the variability in load can be predicted.

The results when using load forecast error instead of the hourly variation of load show that the results based on the simple hourly variations from load and wind power time series, should be doubled if no hour ahead wind forecast is assumed. Applying this to the results of Nordic and Denmark area gives the results presented in Figure 11 and Table 2.

The results show that when the penetration of wind power in the system increases, an increasing amount needs to be allocated for operating reserve. For a single country the increase in reserve requirements can range 2.5-4% of the installed wind power capacity at 10% penetration. The effect of wind power is nearly double in Finland compared to that for Denmark. This is mainly due to the low initial load variability in Finland. When the Nordic system works without bottlenecks of transmission the impact of wind power becomes significant at 10% penetration level, when the increase in reserve requirement due to wind power is about 2% of installed wind power capacity or 310-420 MW. At a high wind power penetration of 20%, the increase is already about 4% of wind power capacity or 1200-1600 MW. The range is for a more-or-less concentrated wind power capacity in the Nordic countries.

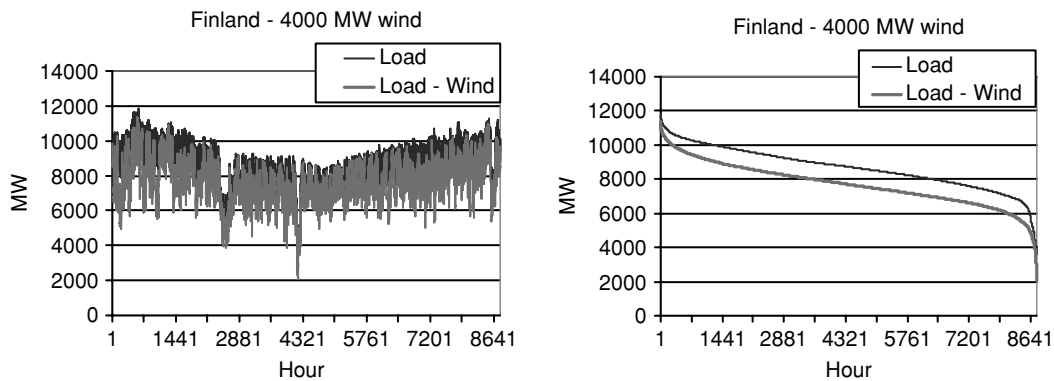


Figure 11: Load and wind data for Finland. The hourly load and net load (load – wind) are presented as time series (left) and as duration curves (right). Data from wind parks is scaled up to wind power penetration of about 11% of gross demand (4000 MW).

Table 2 The increase in reserve requirement due to wind power with 10% penetration level in Finland, Denmark and Nordic countries. The range in Nordic figures is for more or less concentrated wind power. The relative numbers in % are relative to peak load for load variability and relative to installed wind power capacity for the rest of the numbers

	Finland year 2001		Denmark 2000–2002		Nordic 2000–2002	
	MW	% of peak load or capacity	MW	% of peak load or capacity	MW	% of peak load or capacity
Stdev wind hourly variability	103	2.6%		2.9%		1.8–2.0%
Stdev load hourly variability	269	2.3%	273	4.3%	1438	2.1%
Stdev net load hourly variability	288	2.4%	279	4.3%	1485	2.2%
Stdev load forecast error	123	1.0%				
Increase in variability (4σ)	76	1.9%	24	1.2%	155–210	0.8–1.1%
Increase in unforecasted variability (4σ)	150	3.8%	50	2.5%	310–420	1.6–2.2%

The estimation is based on hourly wind power data from a 3-year-period in which the wind resource was less than average. This may underestimate the true variability. For the Danish data, the error was estimated to be on the order of 5%, and it has been added to the results in Figure 11 and in the last section of Table 2.

The reserve requirements due to load and wind ramping within the hour has been assumed to be included in the reserve requirements calculated by the sigma approach.

9. CASE: SWEDEN

The Swedish wind power series were obtained as a result of the project reported in (Magnusson et al, 2004). The so called synthetic time series are based on a database with relevant climatological parameters for the period 1992–2001 and cover the production of 56 wind farms based on locations throughout Sweden. About 40% of the wind farms are located at sea and each has an installed capacity between 50 and 300 MW. These account for 75% of

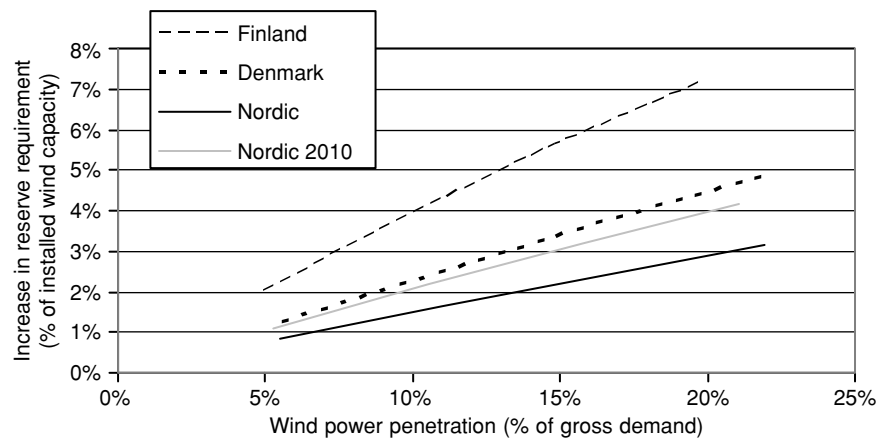


Figure 12: Increase in hourly load following requirement for wind power, calculated from the standard deviation values of load and wind power production from years 2000–2002. Increase is relative to installed wind power capacity.

the total capacity installed. In total, the assumed installed wind power capacity was 4000 MW corresponding to 10 TWh/a of generation.

The load forecast error is calculated from a load database received from Swedish TSO Svenska Kraftnät for the years 2002, 2003, and 2004.

9.1 Comparing Results for Load Variations and Load Forecast Time Series

The power system reserve requirements for different wind power scenarios based on hourly analysis has been calculated in (Axelsson et al, 2005). The statistical method based on 4σ analysis of net load variability was compared with the statistical method including forecast errors. 4000 MW wind power was simulated according to the data from (Magnusson et al, 2004). The results for the different methods of calculating the additional variability in net load in Sweden (increase in reserve requirement) caused by 4000 MW wind power are presented in Table 3.

For wind power two cases for the forecast were used – the persistence an hour ahead (which means no forecast – case load forecast only) and an assumed improvement to persistence by forecasting (case load and wind forecast). The load forecast error is calculated from a load database received from TSO Svenska Kraftnät for the years 2002, 2003, and 2004. Analysis of this data shows that both the variability of the load in Sweden as well as forecast error is larger than in Finland. Standard deviation of hourly load variability in Sweden is 2.4% and forecast error is 1.4% (an improvement by over 40%). The difference between Sweden and Finland can be explained by different proportions of the types of consumers with domination of industrial load in Finland.

At the time of implementation of the study presented in (Axelsson et al, 2005) the main scenario was that most of wind power in future would be implemented offshore and in the southern part of the country. However, recent activity indicates more rapid development of wind power on land both in Southern Sweden and in the North. The new estimations are that about 50% of wind power will be located in the South and 50% in the North. Similarly it is believed that about 50% of installed wind power capacity will be on land and 50% offshore.

This will reduce the variability compared with the calculations reported in (Axelsson et al, 2005). The standard deviation of hourly wind variability would decrease in the 4000 MW case from 73 MW to 58 MW (1.4% of installed wind power capacity) (Table 3). Combining wind variability with load variability results in a net load variability standard deviation of 578 MW

Table 3 Summary of results for the different methods calculating the need for additional reserves in Sweden for 4000 MW wind (6.6% penetration). Peak load 25800 MW has been used for load and net load relative figures. Hourly analysis. The relative numbers in % are relative to peak load for load variability and relative to installed wind power capacity for the rest of the numbers

Wind power (MW)	4000 MW (70% offshore)		4000 MW (50% offshore, more dispersed wind)	
	MW	% of peak load or wind capacity	MW	% of peak load or wind capacity
Stdev wind power hourly variability	73	1.8%	58	1.5%
Stdev load hourly variability	575	2.2%	575	2.2%
Stdev net load hourly variability	579	2.2%	578	2.2%
Stdev load forecast error	339*	1.3%	339*	1.3%
Increase in variability (4σ)	19	0.5%	12	0.3%
Increase in forecast error variability (4σ), load forecast only	31	0.8%	20	0.5%
Increase in forecast error variability (4σ), load and wind forecast	20	0.5%	13	0.3%

*The load forecast error is calculated from load database for the years 2002, 2003 and 2004 and not 1992 to 2001.

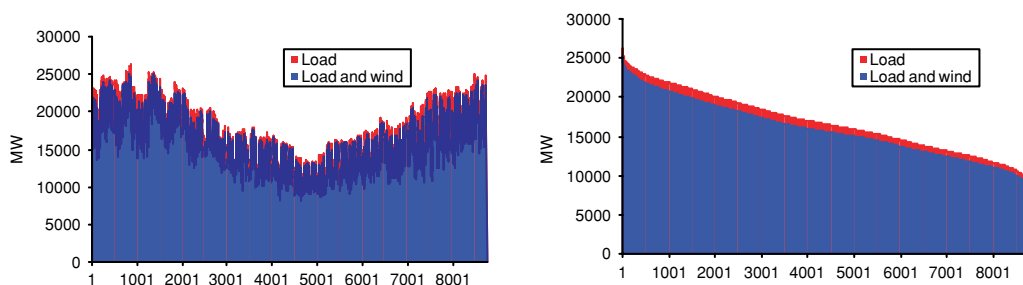


Figure 13: Load and wind data for Sweden (4000 MW wind installed). The hourly load and net load (load – wind) are presented as time series (left) and as duration curves (right).

(2.5%), which results in a 12 MW increase in 4σ variability due to wind power compared with the 19 MW calculated before.

If instead of load variability the load forecast error is used, the corresponding standard deviation of load forecast error will be 334 MW (1.3%) resulting in a 20 MW increase in 4σ variability as compared with 12 MW calculated before. This means that a 67% increase in the result based on load variability will result, when taking into account the better predictability of load. However, taking into account that wind can also be predicted hour ahead, the result is close to the first calculation with simple load and wind variability.

10. SUMMARY OF THE CASE STUDY RESULTS AND CONCLUSIONS

The variability inherent of wind power production will require increased flexibility in the power system when a significant amount of load is covered by wind power. Standard deviation of variability for load and net load (load minus wind power production) has been used when estimating the effect of wind power on the short term reserves of the power

system. This method is straightforward and easy to use when time-series data on wind power and load exist. Net load variability compared to load variability gives an estimate for the needs of the system to react to large scale wind power. A statistical approach using the standard deviation (σ) values gives estimates for the range of variability, for example taking $\pm 4\sigma$ as the range will cover most variations (99.99 % of all variations are inside this range). So far, the multiple of sigmas has been on the order of 6σ for regulation reserves, and in the range of $2\text{--}3\sigma$ for load following reserves. In this paper the sigma approach has been compared with other methods. In this study, the incremental changes to the system due to wind power were estimated for two cases in the US and the Nordic countries.

Minnesota results for a 25% (energy) wind penetration (34 % of peak load) show that the dynamic reserve requirements average 7.6% of installed wind power capacity. The 99th percentile exceedence rule results in a 31% reserve. This is clearly much higher than other results in this paper, or in the international comparison (Holttinen et al, 2007).

Grant County results for a wind penetration level of 10.4% of peak load (63.7 MW of wind divided by a peak system load in 2006 of 610 MW) show an increase in reserve requirement of 0.1% of wind power capacity at regulation time scale (minutes) and 6.3% of wind power capacity at load following time scale (10 minutes), using an exceedence level 99.7%.

The Nordic countries results at 10% penetration (of electrical energy) show that for a single country the increase in reserve requirements can range 2.5–4% of the installed wind power capacity. When the Nordic system works without bottlenecks of transmission the increase in reserve requirement due to wind power is about 2% of installed wind power capacity. At a high wind power penetration of 20%, the increase is about 4% of wind power capacity. For Sweden with a 6.6% penetration level (of electrical energy), the increase in reserve requirement is 0.5–0.8 % of installed wind power capacity.

The results of studies for different countries show that the percentage of reserve requirements related to the installed wind power capacity varies greatly between different systems. The results from US show higher reserve requirement estimates than the results from the Nordic countries. The effect of wind power variability is higher in Finland than in Denmark and Sweden. This is due to the following two main reasons: load variability in Finland is lower than in Sweden or Denmark and wind power variability in Denmark and in Sweden is less than in Finland. In Sweden, wind power is allocated across a larger geographical area, which leads to more smoothing effect for wind power's variability.

The results from US indicate that in the load following time scale the number of sigmas that result in 99% exceedence is between 2.3–2.5 and the number of sigmas for 99.7 % exceedence is 3.4. For regulation time scale the number of sigmas for 99.7 % exceedence is 5.6.

The estimates of increase in variability do not take into account the fact that the variability is easier to predict for the load than for wind power production. The results from the Nordic countries indicate that the number of sigmas should be increased by 67–100 % if better load predictability is taken into account (combining hourly wind variability with load forecast errors).

As more data and other methods for reserve requirement estimation emerge, it is interesting to see how well the general assumptions of multiples of sigma used so far in the studies reflect the increase in reserve requirement needs due to wind power.

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