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VTT Processes

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Abstract

This thesis studies the impact of large amounts of wind power on the Nordic electricity system. The impact on both the technical operation of the power system and the electricity market are investigated.

The variability of wind power is reduced when looking at a large interconnected system with geographically dispersed wind power production. In the Nordic countries, the aggregated wind power production will stay between 1–90 % of the installed capacity and the hourly step changes will be within ±5 % of the installed capacity for most of the time. The reserve requirement for the system, due to wind power, is determined by combining the variations with varying electricity consumption. The increase in reserve requirement is mostly seen on the 15 minutes to 1 hour time scale. The operating reserves in the Nordic countries should be increased by an amount corresponding to about 2 % of wind power capacity when wind power produces 10 % of yearly gross demand. The increased cost of regulation is of the order of 1 €/MWh at 10 % penetration and 2 €/MWh at 20 % penetration. This cost is halved if the investment costs for new reserve capacity are omitted and only the increased use of reserves is taken into account. In addition, prediction errors in wind power day ahead will appear in the regulating power market to an extent which depends on how much they affect the system net balance and how much the balance responsible players will correct the deviations before the actual operating hour.

Simulations of increasing wind power in the Nordic electricity system show that wind power would mainly replace coal fired production and increase transmission between the areas within the Nordic countries and from Nordic countries to Central Europe. The CO_2 emissions decrease from an initial 700 gCO_2/kWh to 620 gCO_2/kWh at 12 % penetration. High penetrations of wind power will lower the Nordpool spot market prices by about 2 €/MWh per 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand).

Preface

This doctor's thesis has been carried out at the Technical Research Centre of Finland VTT[1]. The work was mainly financed by the Nordic Energy Research Programme and Fortum Säätiö (Fortum Foundation), with co-funding from the Finnish Energy Industries Federation Finergy. Part of this work has been co-financed through the EU project "Wind power Integration in Liberalised electricity markets WILMAR" and the national Tekes ClimTech programme research project "The possibilities of wind power for limiting climate change".

First of all I want to thank the wind power producers and power companies for providing data without which a large part of this thesis would not have been possible. The use of energy system models EMPS in SINTEF, Norway, and SIVAEL in Eltra, Denmark is acknowledged.

My supervisor professor Peter Lund and my instructor docent Ritva Hirvonen[2] have given me valuable comments related to the work, for which I am grateful. This work is the fruit of Nordic co-operation – visiting research institutes and power companies in Denmark, Norway and Sweden has given me the opportunity to use different models and obtain data for this thesis as well as interesting discussions on the Nordic power system. I wish to extend special thanks to the following persons for both organising and contributing to my successful visits: Klaus-Ole Vogstad, Audun Botterud, Birger Mo in NTNU/SINTEF Energy Research; Gregor Giebel, Erik Lundtang Petersen, Poul-Erik Morthorst in Risø National Laboratories; Hans Ravn and Claus Nielsen in Elkraft System; Jens Pedersen and Peter Børre Eriksen in Eltra; Torben Nielsen and Henrik Madsen at IMM/DTU; Lars Tallhaug in Kjeller Vindteknikk and Lennart Söder in KTH. In Finland, the wind power team as well as the energy systems group at VTT have provided a good working environment, special thanks for discussions go to Esa Peltola, Bettina Lemström and Göran Koreneff.

Last but not least, my family has given me the hugs and kisses needed to keep me going. Special thanks for the patience of my daughters Sara and Meri, not getting angry when the mother had eaten the last chocolate biscuits. And to my dear husband Esa, for his love and impatience.

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[1] VTT Processes, Energy production research area, Distributed energy group
[2] currently working at Energy Market Authority EMA

List of publications

The thesis consists of the following publications:

A. Holttinen, H., Hirvonen, R. 2005. Power system requirements for wind power. Chapter 8 in Wind Power in Power Systems. Ed. by Ackermann, T. John Wiley & Sons Ltd. Pp. 144–167. ISBN 0-470-85508-8 (HB). (In print.)

B. Holttinen, H. 2005. Hourly wind power variations in the Nordic countries. Wind Energy. (In print.)

C. Holttinen, H. 2005. Impact of hourly wind power variations on the system operation in the Nordic countries. Wind Energy. (In print.)

D. Nørgård, P., Holttinen, H. 2004. A Multi-Turbine Power Curve. In: Proceedings of Nordic Wind Power Conference NWPC'04, 1.–2.3.2004. Gothenburg, Sweden. 5 p. Submitted to Wind Energy.

E. Holttinen, H., Pedersen, J. 2003. The effect of large-scale wind power on a thermal system operation. In: Proceedings of the 4th International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms. 20.–22. Oct. 2003, Billund, Denmark. KTH, Stockholm, Sweden, Denmark. 7 p.

F. Holttinen, H., Vogstad, K.-O., Botterud, A., Hirvonen, R. 2001. Effects of large scale wind production on the Nordic electricity market. Proceedings of European Wind Energy Conference, Wind Energy for the New Millenium, EWEC'2001, July 2–6th, 2001, Copenhagen, Denmark. 4 p.

G. Holttinen, H., Tuhkanen, S. 2004. The effect of wind power on CO_2 abatement in the Nordic Countries. Energy Policy, Vol. 32/14, pp. 1639–1652.

H. Holttinen, H. 2005. Optimal electricity market for wind power. Energy Policy. (In print.)

Publication A is a summary of the impact wind power has on power systems, presenting the knowledge so far of the extent of the impact.

Publications B and C study the operating reserve requirements of wind power, based on hourly wind power production data. In publication B, large scale wind power production is studied, looking at statistical parameters defining the smoothing effect of the production time series from geographically dispersed production. In C, the data is used together with synchronous load data to reveal the incremental effect of wind power fluctuations on the variability of load that the power system will experience. The method developed in publication D is used in publication B when working with wind speed time series. The method aims to make a single point measurement represent wind farm production of a larger area.

In publications E and F, the operation of the power system is studied via simulations with increasing amounts of wind power. In E, the focus is on the thermal system operation with hourly level simulations of the West Denmark power system. In F, the focus is on the effects on the hydro power system and the Nordic electricity market.

In Publication G, the role of wind energy in reducing CO_2 emissions is studied. Energy system simulation models are used to find out what production forms and fuels wind energy would replace in the Nordic and Finnish energy systems.

Publication H studies wind energy in the electricity markets. The short term prediction of wind power production and the challenge of wind power production in a day-ahead market are described. A case study based on realised data for year 2001 is presented, where the benefits of more flexible market mechanisms are illustrated from a wind power producers' point of view.

Own contribution

The author has been the main person responsible for writing the publications, making the analyses and drawing the conclusions, except for publication D. In publication A, the co-author wrote section 2. In publication G, the co-author wrote chapter 3, carried out the corresponding simulations and participated in the analysis of the results. For publications E and F, the co-authors were involved in forming the input files, and helping to run the model and interpret the results. However, the simulation set-up and scope of the work was by the author. For publication D, the main author is responsible for the writing and formulating the multi-turbine power curve approach and my contribution as a co-author has been to join the discussions and provide the examples of how the method works.

Contents

List of symbols

a	annuity factor
c_p	capacity factor of wind power (production divided by time of operation and nominal capacity)
CHP	combined heat and power
CO_2	carbon dioxide
EFOM	Energy Flow Optimisation Model
EMPS	EFI’s Multi-Area Power market Simulator model
GHG	green-house gas(es)
LOLP	loss-of-load-probability
n	number of data sets / wind farms
NGCC	natural gas combined-cycle (power plant)
SIVAEL	planning model for heat and power production
TEP	tradable emission permits
TGC	tradable green certificates
TSO	transmission system operator
σ	standard deviation
σ_L	standard deviation of load
σ_{NL}	standard deviation of net load

1. Introduction: wind power status and future trends

Wind energy is a renewable electricity production form converting the kinetic energy of moving air masses into electricity. Wind power is characterised as distributed generation with the exception of large offshore wind farms which are power plants more than 100 MW in size.

Wind power has experienced a rapid global growth since the 1990's. At the beginning of 2004, there were 40 GW installed worldwide increasing by 8 GW per year. The annual growth rate is expected to reach 15 GW/a in 2010 (BTMConsult, 2004). The major market area for wind power is the European Union with nearly 30 GW installed capacity. In the Nordic countries, the installed wind power capacity at the end of year 2003 was 3076 MW in Denmark, 428 MW in Sweden, 101 MW in Norway and 53 MW in Finland (BTMConsult, 2004).

The high growth rate of wind power capacity is explained by the cost reductions in the 1980's and 1990's as well as by public subsidies in many countries, linked to efforts to increase renewable power production and to reduce CO_2 emissions. Further cost reduction is anticipated (Dale et al., 2004). The production cost of wind power now ranges between 30–70 €/MWh[3].

Wind power production is highly dependent on the wind resources at the site. Therefore the average production, the distribution of the production, as well as the seasonal and diurnal variations may look very different in different areas of the world as well as at different sites within an area. For most sites on land, the average power as the percentage of the nominal capacity (capacity factor c_p), is between 20 and 40 %. This can be expressed as full load hours of 1800–3500 h/a. Full load hours are the annual production divided by the nominal capacity. Offshore wind power production, or some extremely good sites on land, can reach up to 4000–5000 full load hours (c_p = 45–60 %).

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[3] Without subsidies, 20 years and 5 % interest rate for the investment. Assumptions: the range of investment costs 800–1200 €/kW, the range of production 1800 h/a–3000 h/a, operation and maintenance costs 8–12 €/MWh.

We can compare the above figures to other forms of power generation. Combined heat and power production (CHP) has full load hours in the range of 4000–5000 h/a, nuclear power 7000–8000 h/a, and coal fired power plants 5000–6000 h/a. However, full load hours are only used to compare different power plants. They do not tell us how many hours the power plant is actually in operation. Wind turbines, which operate most of the time at less than half of the nominal capacity, will typically produce power during 6000–8000 h/a (70–90% of the time).

In 2003, wind energy produced about 2 % of the electricity consumption in the EU, the largest shares being 16 % in Denmark (21 % in West Denmark), 4 % in Germany (about 30 % in Schleswig Holstein) and 5 % in Spain (about 50 % in Navarra) (Eltra, 2004; Elkraft, 2004; Ender, 2004; ISET, 2004; EWEA, 2004). The projection for year 2010 is 75 GW in EU (EWEA, 2004). With increasing penetration[4], the integration of wind power and the extra costs of absorbing an intermittent energy source in the power system become highly relevant.

The expected developments of wind power technology will affect the extent of the impact that wind power has on the power system. Very large wind farms (hundreds of MW) is one trend that can pose serious challenges to the integration of wind power. They concentrate the capacity to a few sites and the smoothing effect of variations by geographical spreading can be partly lost. However, large wind farms will also pave the way for other technologies that will help with integration. Increasingly sophisticated power electronics and computerised controls in wind farms, as well as an improved accuracy of wind forecasts, will lead to improvements in the predictability and controllability of wind power. Large wind energy power plants will mean that there are new requirements regarding the integration of wind power into the power system. Increasingly, wind farms will be required to remain connected to the grid when there are faults in the system, providing power production and reactive power support during the fault.

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[4] **Penetration:** in this study the concept energy penetration is used. Wind energy penetration is the yearly wind power production as percentage of the yearly total electricity consumption (gross demand). Capacity penetration is another concept, where the wind power capacity relative to the total installed generation capacity of an area is used.

2. Setting the scene: previous work and the scope of this thesis

The drawbacks of wind power, from the power system point of view, are its variability and unpredictability. However, these problems are greatly reduced when wind power is connected to larger power systems, which can take advantage of the natural diversity in variable sources. Large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output.

2.1 Previous work on power system impacts of wind power

(Publication A)

The integration of wind power into regional power systems has mainly been studied on a theoretical basis, as wind power penetration is still rather limited. Even though the average annual wind power penetration in some island systems (e.g. Crete in Greece) or countries (e.g. Denmark) is already high, on average wind power generation represents only 1–2 % of the total power generation in the Nordic power system (Nordel) or the Central European system (UCTE). The penetration levels in the USA (regional systems) are even lower.

The need for more flexibility to meet larger fluctuations in the system depends on the portion of consumption covered by wind power production. It is relevant to know how the wind power is geographically dispersed, to account for the smoothing of variations, as well as the general patterns in the wind power production of the area (the amount of diurnal variation and its coincidence with load patterns). Also, power systems are different in how much inherent variability in the system (the load) there is and in how loaded and well meshed the system is (available transmission). The amount of flexibility already there in the system, as well as the amount that can be cost effectively increased is important. The treatment of imbalances in the power systems differs internationally.

The system impacts of wind energy are presented schematically in Figure 1. These impacts are divided into two parts: short term, balancing the system during the operational time scale (minutes to hours), and long term, providing enough power and energy in peak load situations.

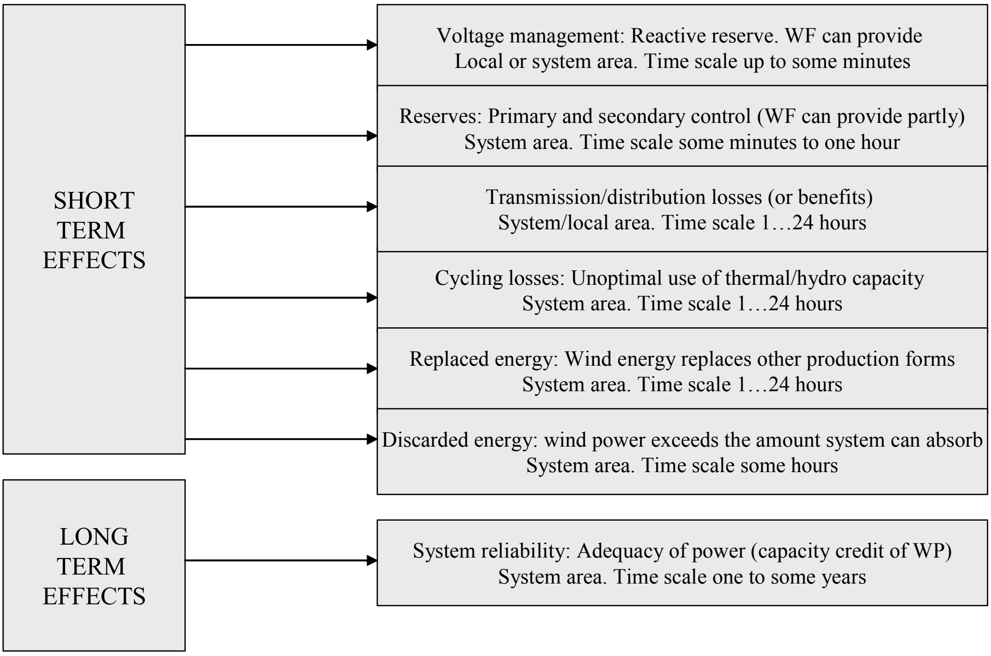

Figure 1. System impacts of wind power (WP) and wind farms (WF), causing integration costs. Part of the impacts can be beneficial for the system, and wind power can have a value, not only costs.

Voltage management is a more local issue, where measures should be taken when wind farms are installed. There is already technology which allows wind farms to benefit power system operation: modern wind farms can be equipped with power electronics providing voltage management, reactive reserve and some primary control (Kristoffersen et al., 2002).

Wind power can either decrease or increase the **transmission and distribution losses** depending on where it is situated in relation to the load. An example from a study made for the UK shows that concentrating the wind power generation in the North would double the estimated extra transmission costs to 2 and 3 €/MWh at a wind power penetration level of 20–30 %. This would not be the case if production was more geographically dispersed. According to the study, at more modest penetration levels transmission costs would decrease (ILEX, 2003). First experiences from West Denmark and the northern coast of Germany have shown that when significant amounts of electrical demand are covered with wind power, it is first seen as increased transmission with neighbouring countries or areas (Eriksen et al., 2002; Lund & Münster, 2003). Increased transmission between regions can lead to an increase in bottlenecks of transmission (Matevosyan, 2004).

Discarded energy occurs only at substantial penetration and it depends strongly on the operational strategy of the power system. The maximum production of wind power is many times larger than the average power produced. This means that at a wind power penetration of about 20 % of the gross demand, wind power production may equal the demand during some hours (a 100 % instant penetration). When wind power production exceeds the amount that can be safely absorbed while maintaining adequate reserve and dynamic control of the system, a part of the wind energy produced may have to be curtailed. This is especially pronounced in island systems not having the possibility of transmission between areas to fully account for the smoothing effects of large scale wind power. Studies on thermal systems show that about 10 % (energy) penetration is the starting point where a curtailing of wind power may become necessary. When wind power production is about 20 % of yearly consumption, the amount of discarded energy will become substantial and about 10 % of the total wind power produced will be lost. (GarradHassan, 2003; Giebel, 2001). In West Denmark, few occasions of curtailment have occurred since the year 2001 when wind power exceeded 16 % penetration on a yearly basis.

For the short term effects of wind power on reserves and cyclic losses, the main cause is the fluctuation of wind power production. The extent of wind power variability has been the subject of several studies. Many studies have been based on wind speed data from several geographically dispersed measurement masts, converting wind speeds first to higher altitude (hub height of wind turbines) and then to the production of a single wind turbine using a power curve. There are possible caveats; first of all in up-scaling the wind to higher altitudes, as the wind profile is dependent on atmospheric conditions (vanWijk, 1990), and secondly, in using a single point measurement to represent a wind farm stretching several kilometres in dimensions. Simulated wind power production tends to exaggerate the fluctuations. Studies based on actual wind power production are rare, due to the fact that large scale wind power production has only started to emerge in the past few years (Ernst, 1999; Wan, 2001). A study of the smoothing effect and its saturation has been made for the northern part of Germany (Focken et al., 2001). As concluded in several studies in the USA (Smith et al., 2004), it has become clear that to estimate the impacts of wind power on the power system, the wind induced imbalances have to be treated together with aggregated system imbalances. The results from estimating the **increased reserve requirements** show a very small impact on primary reserve (regulation time scale) (Ernst, 1999; Smith et al., 2004; Kirby et al., 2003; Dany, 2001). For secondary reserve (load following time scale), there is an increasing impact with increasing penetration (Milborrow, 2001; Milligan, 2003; ILEX, 2003). The first estimates regarding the increase in secondary (load following) reserves in the UK and US thermal systems suggest 2–3 €/MWh for a penetration of 10 % and 3–4 €/MWh for higher penetration levels (Smith et al., 2004; Milborrow, 2001; ILEX, 2003; Dale et al., 2004)[5]. It is difficult to compare the results from the studies made so far. The different results for the cost estimates are due to different system characteristics, penetration levels and study methods. The studies made so far often use simulated wind power output data that exaggerates the variations in wind power production, and make conservative assumptions unfavourable to wind power. A caveat in some of the studies is a modelling approach not taking into account the flexibility in the system, such as hydro power (Dragoon & Milligan, 2003). Also, the division of integration costs to different time scales of reserves varies, and the cost of increased reserve requirements is not always documented (Dale et al., 2004). For the Nordic countries, the impact of wind power on balancing the system on an hourly time scale has not been studied before this study.

In the time scale of unit commitment (4–24 h), wind power can cause extra costs for the system, if the operation of the power plants is made more inefficient due to varying wind power production and prediction errors. The positive effects of wind power, reduced fuel use and emissions are also issues relevant in this time scale. Day-ahead predictions are required in order to schedule conventional units

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[5] Currency exchange rate from the end of 2003 used: 1 € = 1.263 $; 1 € = 0.705 £

(Giebel et al., 2003). Simulations of system operation with different levels of wind power prediction errors show that minimising prediction error increases the benefits of the wind plant measured as fuel savings from the conventional units. However, both the system in question (production mix and load variations) and the properties of wind power production (correlation with load) have a strong effect on the results of how much benefit the improved predictions bring about (Milligan et al., 1995). For a thermal system, the effects depend on the strategy of operation, over or under committing the plants due to wind power (Persaud et al., 2003). Ramping rates have not proved to be a problem (Persaud et al., 2003; Dany, 2001). The decrease of efficiency in the hydro power system of Sweden due to the forecast errors of wind power production would be equivalent to 1 % of the wind power production at a wind power penetration of 4 % of the yearly gross demand (Söder, 1994).

Power system studies are often carried out considering the system as it was operating before the liberalisation of electricity markets. Balancing the forecast errors between the bids and the delivery is the responsibility of the power producer (Wibroe et al., 2003; KEMA, 2002). Theoretical studies on how wind power would come to the markets have shown that market design has a crucial effect on wind power producers in how the regulating costs are allocated (Hutting & Clejne, 1999; Nielsen et al., 1999). In West Denmark, with a wind penetration of about 20 %, it is the responsibility of the transmission system operator (TSO) to balance the so-called prioritised production. The cost for compensating forecast errors in the day-ahead market at the regulating market has amounted to almost 3 €/MWh (Eriksen et al., 2002). Market rules can also change the bidding strategy from simply minimising the error in forecasted energy (Bathurst et al., 2002; Nielsen & Ravn, 2003). In the USA, due to the new set up in which generators have to self-supply or purchase ancillary services, the regulation burden of one single project has been evaluated by several studies, showing a cost of 1–3 €/MWh (Hirst, 2002; Smith et al., 2004). However, for Europe or the Nordic countries this is not relevant, as ancillary services are defined for large interconnected systems where any considerable amount of wind power would mean thousands of turbines in tens or hundreds of sites.

The long term effects concerning the adequacy of supply involve the estimation of capacity value for wind power. The ability of wind power to offset conventional capacity, capacity credit, has been widely studied. The results of several studies of wind power capacity credit (Milligan, 2000; Giebel, 2001; Peltola & Petäjä, 1990; Kirby et al., 2003) show that at low wind power penetration the capacity credit is close to the average production of wind power during times of high loads. When wind power penetration is increased, the capacity credit will decrease. For example, for the UK, it has been estimated that at low penetration, the capacity credit is 35 % of installed wind power capacity, decreasing to 20 % of installed capacity at 20 % penetration (ILEX, 2003; Dale et al., 2004). In the liberalised electricity markets, the capacity credit is no longer routinely used for comparing the production forms. However, the adequacy of power systems also has to be maintained in the long term, and knowledge to what extent wind power can be relied upon is required.

2.2 Objectives and approach of the thesis

Increasing penetration levels of a new, variable production form raise concern for the system operators regarding system reliability. Knowledge about the extent of variations and production patterns, and analyses together with system variables are needed to ensure system adequacy and security with increasing penetration levels of wind power. Integration costs, or system costs, are the costs incurred to incorporate the electricity from a generation source into a real-time electricity supply, ensuring system security. The power system works for the consumers, and they also pay the system cost in their tariffs, as they pay for the production, distribution and taxes. It is not usually necessary to allocate these system costs to a certain producer or consumer. However, when setting the policy to subsidise renewable production, there is a need to quantify the system costs of wind power; environmental goals need to consider economic efficiency as well as security of supply. Estimating the real potential of wind power in reducing CO_2 emissions involves estimating all of the costs involved.

This thesis aims to produce an overall picture of the impacts of wind power on the power system in the Nordic countries. The focus is on estimating the order of magnitude for the extra costs due to integration of wind power at penetration levels of 10–20 % of the gross demand.

What this thesis is about. The work concentrates on the impact of large scale wind power on the power system operation in the Nordic countries, on a time scale from some minutes to some days. The emphasis is on short term effects – impacts on operating reserves and operation of thermal/hydro plants as well as replaced energy, replaced fossil fuels and reduced CO_2 emissions. Wind power in the Nordic electricity market is discussed in detail.

In this thesis, the main focus is on short term effects, mainly reserves (Figure 1). Cyclic losses, discarded energy and increased transmission between the areas in the Nordic power system are also touched upon. The long term effects are already well covered in the literature, but some analyses made during this thesis gave insight into system adequacy as well.

What this thesis is NOT about. The thesis excludes such areas as the investments and incentives needed for large scale wind power, including possible grid reinforcements (ILEX, 2003; KEMA, 2002). The local issues of power system reliability related to voltage management, system stability or power quality are also beyond of the scope of this thesis. The starting point for this thesis is that large scale wind power is already in the power system and is connected to the network according to grid codes specified to maintain power quality and system stability.

To study the impact of wind power on a large interconnected power system, two basic approaches can be used: simulating the system operation or using analytical methods based on available data. Both methods have been used in this thesis. First, existing energy system models were sought and simulations with increasing amounts of wind power were run to see the effects of wind power production on the rest of the power system. The emphasis was on models in the Nordic area simulating the operation of the power system. Secondly, realised data for wind power production, the varying load and electricity market prices, were analysed to study the variability of wind power together with the varying load, as well as the market operation of wind power. This approach took advantage of the situation in West Denmark, where large scale wind power has been a reality since the 90's and the wind power penetration has exceeded 15 % of gross demand since the year 2000. The data contains the properties of large scale wind power with the smoothing effect of thousands of turbines. Several years of data contain different low and high wind and load situations as well as the situations of low and high load and wind variations. The data implicitly includes the effect of wind power on the market price.

2.3 The geographical area of the study: the Nordic countries

The common liberalised Nordic electricity market covers Norway, Sweden, Finland and Denmark. East Denmark is part of the Nordel system, and West Denmark is part of the Central Europe UCTE system. West and East Denmark are not connected by a transmission line, but are both connected to Sweden and Germany, and West Denmark also to Norway. Sweden, Norway and Finland are well interconnected: the transmission capacity exceeds 2000 MW between Norway and Sweden and 1000 MW between Finland and Sweden. In addition, Sweden and Denmark have interconnections to Central Europe (in total 2000 MW) and Finland to Russia.

The production mix is shown in Figure 2. A large share of hydro power is characteristic for the Nordic countries: Norway covers almost 100 %, Sweden almost 50 % and Finland almost 20 % of the electricity consumption by hydro power.

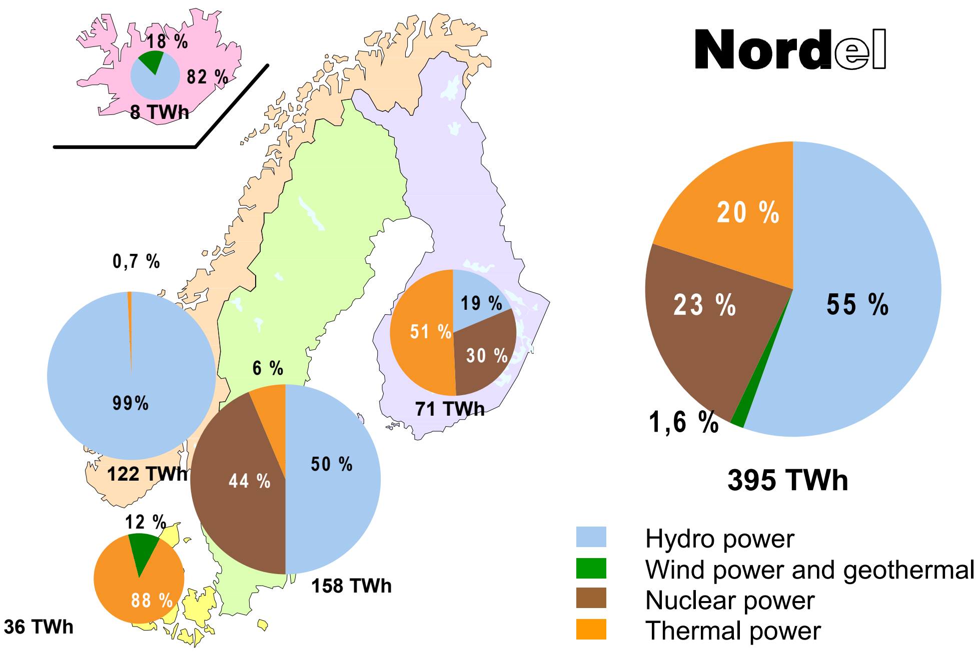

Figure 2. Electricity production in the Nordic countries in 2001. Installed power plant capacity is about 90 GW. (Source: Nordel/Finergy.)

3. Description of the models and data used in the thesis

Three energy system models were used in this thesis. To study the impact of wind power on a thermal power system, the planning tool SIVAEL for West Denmark was used (Pedersen, 1990). This tool optimises the hourly dispatch during one operating year. To study the impact of wind power on the Nordic electricity market as well as on the hydro power system the EMPS model was used (SINTEF, 2004). This model optimises the operation of the system for one year with weekly time steps. For future CO_2 reduction estimates, the EFOM model for Finland was used, optimising the investment and use of production capacity. At the end of this chapter the data used in this thesis is described, also covering the wind power inputs to the models.

3.1 SIVAEL model

SIVAEL is a simulation model developed in Denmark for electricity and heat production planning purposes (Pedersen, 1990). It is an hourly dispatch/unit commitment model, scheduling the starts and stops as well as unit production rates of power and heat. The scheduling is based on minimising the total variable costs including operational, maintenance, and start-up costs of both electricity and heat production. Operational constraints in the optimisation consist of fulfilling the electricity and heat demands while taking care of the reserve requirements given as input. Unit commitment involves dynamic programming. The model has an iteration loop to fulfil both the local heat demands and the electricity demand for the whole area. Reserve requirement (spinning reserves, secondary reserves and load following) is taken into account as a given percentage of hourly load. Reserves are allocated as part load operation of thermal plants: making sure that the required amount will be available as reserve means not allowing all the plants to reach full power or minimum power. Wind power production is modelled as an hourly profile (8760 hours). The latest version of SIVAEL also includes the forecast errors of wind power. The model uses simulated predictions for unit commitment and dispatch. The regulation requirement due to wind power is calculated as the difference between predicted and actual wind power production and it is allocated to either thermal plants or exchange to neighbouring countries (Pedersen & Eriksen, 2003). The input and scenarios run are described in more detail in publication E.

The SIVAEL model is used for the electricity system planning in a single region. The strength is detailed simulation of the thermal units on hourly basis, with realistic large scale wind power input, capturing the variability of wind power. The weakness is that it is for one region only, so it is not able to take into account the transmission possibilities in a realistic way.

3.2 EMPS model

The power market model EMPS is a commercial tool developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting (Flatabø et al. 1998; SINTEF 2004). EMPS simulates the whole of the Nordic market area. The market is divided into areas with transmission capacities between the areas. Central Europe is modelled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities. The main substance of the model is the detailed optimisation of the hydro system. The hydro power producers try to save the water in the reservoirs for the critical times of high consumption during the winter, when they get the best price for their production and also when the system needs all the power available to cover the load. To determine the way that the limited amount of water in the reservoirs can be used most cost-effectively, the value for stored water is calculated. These so called water values vary both by the time of year and by the current reservoir content and anticipated water inflow to the reservoirs. Water values are calculated by a stochastic dynamic programming algorithm, maximising the value of hydro production (Flatabø et al., 1998). The model simulates the operation of the Nordic day-ahead market, described in more detail in chapter 4 (Figure 4). The water values are used as the marginal cost for hydro power production. For the thermal capacity, the operating costs for the production are used, from input data. The simulation in this thesis is made for one year, with weekly time steps. The model simulates the market price, production and export/import for each area. The input data and scenarios run are described in more detail in publications F and G.

The EMPS model is designed to simulate the electricity market price, taking into account the large hydro power share in the market, and scheduling the hydro power production from the large reservoirs in an optimal way. The strength in EMPS is that it can simulate the different production units in a large, interconnected area. Therefore, it is able to look in detail to what forms of energy wind power will replace in a hydro-thermal system during a large number of different high and low load situations with 30 years of inflow and wind power data. Wind power is modelled as a run-of-river plant and the uncertainty will be included in the simulations. The weakness of EMPS is that wind power simulation is with weekly steps, losing thus information on the variability of wind.

3.3 EFOM model

In EFOM, the whole system is represented as a network of energy or material chains. The network of the described energy system starts from the primary energy supply and ends in the consumption sectors. EFOM is a bottom-up model and it is driven by an exogenous demand for useful or final energy in the consumption sectors. The Finnish EFOM model includes descriptions of other activities that emit greenhouse gases (e.g. waste management and agriculture) and, due to national characteristics, detailed subsystems for e.g. domestic fuel supply, pulp and paper industry, and combined heat and power production. The system is optimised by linear programming, using the total present value costs of the entire system over the whole study period as the objective function which is to be minimised. The whole study period is divided into sub-periods, which can be of different length. In this thesis, the period is 2000–2025 and the time step is 5 years. The year is divided into winter and summer seasons and therefore the seasonal changes e.g. in wind and hydro power production can be taken into account. In EFOM, the GHG emissions from the energy system are calculated directly by multiplying the annual fuel use with the corresponding emission factor. The input data and scenarios run are described in more detail in publication G.

The EFOM model is mainly used for long-term energy and environmental policy support studies at the national level. All calculations are carried out on an annual basis and only seasonal changes can be taken into account. Consequently, factors such as variation of power production, consumption and cross-border trading are clearly beyond the scope of the model. On the other hand, EFOM enables estimation of the cost of different kind of greenhouse gas abatement measures. Due to the nature of the model, both capacity extension and replacement of present capacity are results of optimisation.

3.4 Hourly wind power production data

Hourly data was collected from example years 2000–2002 to study the variations and reserve requirements of wind power (Figure 3).

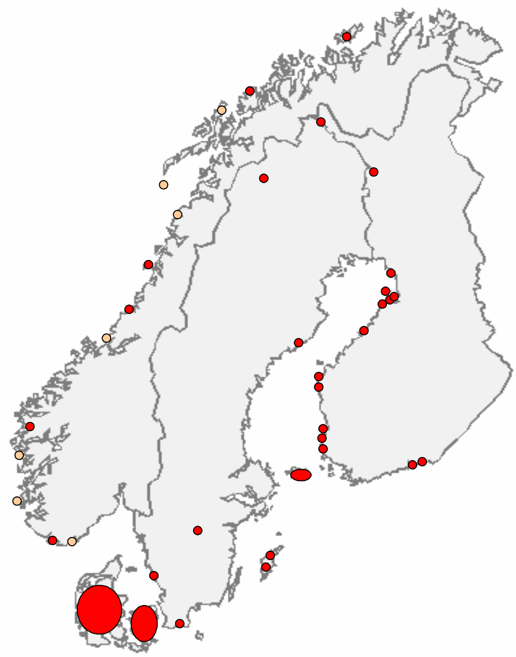

Figure 3. Data for hourly wind power production was available from 21 sites in Finland, 6 sites in Sweden, 6–12 sites in Norway and the aggregated total production of hundreds of sites in Denmark West and East. From the lighter coloured sites data was available for different lengths of time during the study period 2000–2002.

The time period used, 2000–2002, gives a wind power production that is somewhat less than average: 90 % of the average production in Denmark, 87 % in Finland and 96 % in Sweden. The data handling principles and the representativeness of the data were studied in detail in Publication B. The hourly variations were judged representative for Denmark, Finland and a total Nordic time series.

3.5 Wind power data for the models

For the models used in this thesis, representative input data for wind power is crucial for the credibility of the results.

For SIVAEL simulations for the West Denmark region, one year of hourly onshore and offshore wind power production time series were used, based on real hourly production and offshore wind speed data from the region scaled to represent an average wind year. Realised hourly data for 2001 was used as an alternative input together with price data from the same year.

For EMPS simulations, weekly wind power production profiles over 30 years 1961–1990 were used, derived from wind speed measurements (historical wind measurements were used from 3 sites in Norway and Sweden, 1 site in Denmark and Finland respectively). The weekly average was found to be quite representative for the wind power production profile, even if few data series were used. This data will slightly exaggerate the weekly variations, compared with weekly averages calculated from hourly dispersed wind power production.

For EFOM simulations, the Finnish wind power production was described by yearly average wind power production. Onshore and offshore wind power production were split into summer and winter seasons.

3.6 Other data used

Hourly data for the load in the Nordic countries, and CHP production in Denmark and Finland for 2000–2002 were used (publication C).

For 2001, half hourly data for wind power predictions made in West Denmark, and electricity market data for Elspot, Elbas and the Danish regulation market was used (publication H).

4. Production as a part of the power system: Nordic electricity market

(Publications A and C)

Electric power systems include power plants, consumers of electric energy and transmission and distribution networks connecting the production and consumption sites. The operation of the power system involves providing a total amount of electricity, at each instant, corresponding to a varying load from the electricity consumption. The power system, which is operated synchronously, has the same frequency. With the nominal frequency, 50 Hz, the production and consumption (including losses in transmission and distribution) are in balance. When the frequency is below 50 Hz, the consumption of electric energy is higher than the production. If the frequency is above 50 Hz, the consumption of electric energy is lower than the production. This constantly fluctuating interconnected system should maintain the balance so that faults and disturbances are cleared with the smallest disadvantage in the delivery of electricity.

4.1 Merit order of electricity production

Power systems comprise a wide variety of generating plant types, which have a range of capital and operating costs. To produce power cost effectively, the power plants running at low operational costs will be kept running almost all the time (base load demand), and the power plants with higher costs will be run only when the load is high. When ignoring second order costs (such as start-up, shutdown and reserves) plants can be stacked in merit order, where production with low marginal costs run first. Wind power plants as well as other variable sources like solar and tidal have very low marginal costs, usually assumed as 0, so they come to the top of the merit order, i.e., their power is used whenever available (Grubb, 1991).

The electricity markets operate in a similar way, at least theoretically. The price the producers bid to the market is slightly higher than their variable cost, because it is cost effective for the producers to operate as long as they get a price higher than their direct costs. When the market is cleared, the power plants operating at lowest bids come first. The market price at each hour is determined by the market cross as the intersection of supply and demand curves, which can be drawn from the bids for supply and demand (Figure 4).

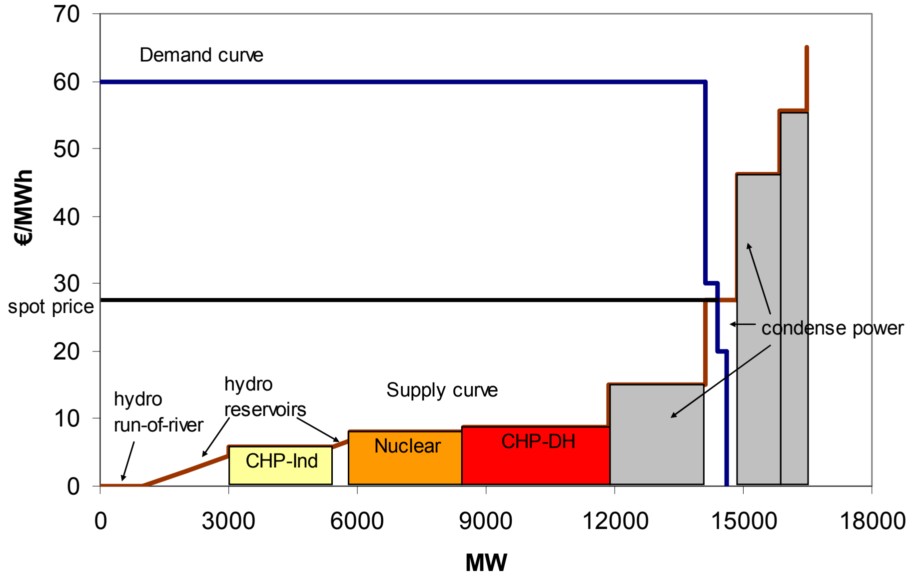

Figure 4. Market cross: spot price formation in the electricity market. Wind power will appear in the supply curve, like the run-of-river hydro plants. The amounts and prices are not based on real data.

In the Nordic countries, hourly production can be traded at the Nordpool spot market. The market is cleared at noon, for the bids for the 24 hours the following day, 12–36 hours ahead. There also exists an after-sales market Elbas[6], with continuous trade which closes one hour before delivery.

[6] It seems probable that this market will be operational in all the Nordic countries in the future, currently it is operating in Finland, Sweden and East Denmark.

4.2 Reserves

Failure to keep the electricity system running has serious and costly consequences, thus the reliability of the system has to be kept at a very high level. Security of supply needs to be maintained in both the short and the long term. This means maintaining both the flexibility and reserves necessary to keep the power system operating under a range of conditions, including peak load situations. These conditions include credible plant outages (disturbance reserves) as well as predictable and uncertain variations in load and in primary generation resources, including wind (operational reserves).

Load following is performed partly beforehand as scheduling and dispatch of power plants according to the load forecast and partly by operational reserves to balance the load forecast errors. Scheduling includes planning the start-ups and shut downs of slower power plants, called unit commitment, in the time scale of 3–12 hours. Optimising the use of the water stored in hydro power reservoirs, the hydro power plants take into account an even longer scheduling horizon. The scheduling can be based on electricity market operation, where bids for production and bids for consumption based on forecasts are made. Figure 5 shows an example of the actual load in the power system over 3 hours compared to hourly forecasted load, denoting forecast errors and short-term load deviations in the system.

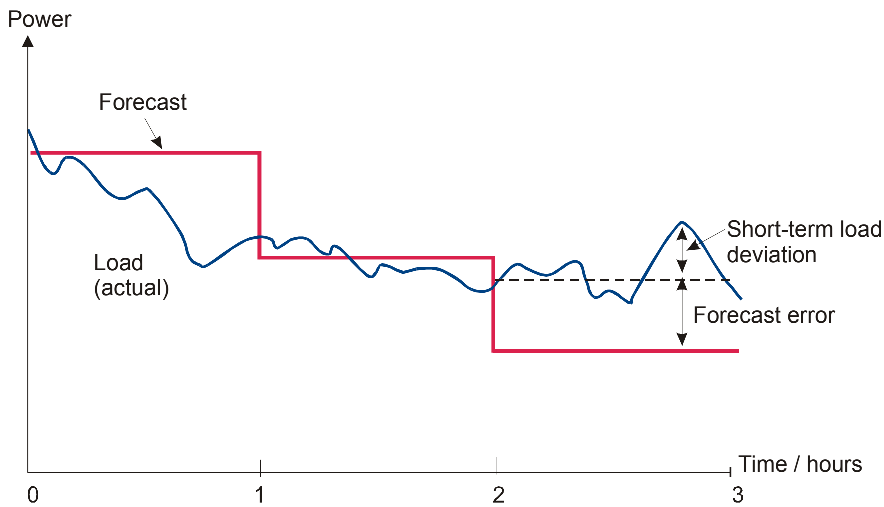

Figure 5. Example of actual load in the system over 3 hours compared to forecasted load.

Both the operational and disturbance reserves are divided into different categories according to the time scale within which they are operating. An example of how the reserves operate is illustrated in Figure 6. It shows the frequency of the system and activation of reserves as a function of time when a large power plant is disconnected from the power system. Activation of reserves divides the reserves into primary reserve (also called instantaneous or automatic reserve), secondary reserve (also called fast reserve) and long-term reserve (also called slow or tertiary reserve). Primary reserve is activated automatically by frequency fluctuations. Secondary reserve is active or reactive power activated manually or automatically in 10 to 15 minutes after the occurrence of frequency deviation from nominal frequency. It replaces the primary reserve and it will be in operation until long-term reserves substitute it as seen from Figure 6. The secondary reserve consists of spinning reserve (hydro or thermal plants in part load operation) and standing reserve (rapidly starting gas turbine power plants and load shedding).

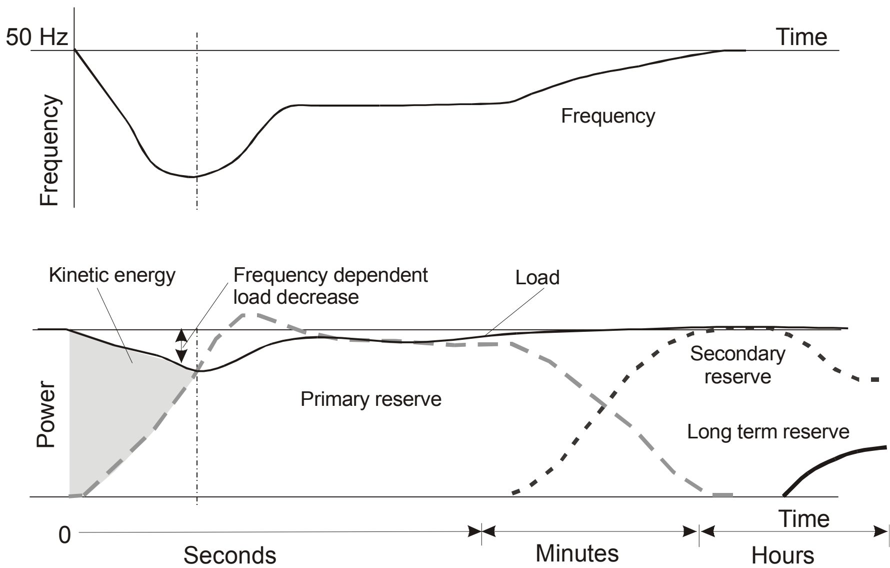

Figure 6. Activation of power reserves and frequency of power system as a function of time when a large power plant is disconnected from the power system (Hirvonen, 2000).

In addition to frequency control, the voltage level is managed to prevent under- and over-voltages in the power system and to minimise grid losses. Frequency is a wide area quantity. Measures can be taken anywhere in the system to maintain the balance, as long as transmission capacity is available. Voltage is a local quantity, and voltage management should be taken care of in the vicinity of imbalances. In order to manage the voltage level during disturbances, reactive reserves in power plants are allocated to the system. These reserves are mainly used as primary reserves in order to guarantee that the voltage level of the power system remains stable during disturbances. Power plants and special equipment, e.g. capacitors and reactors, control the reactive power. The voltage ratio of different voltage levels can be adjusted by tap-changers in power transformers. This requires a reactive power flow between different voltage levels.

The operation of the power system also has to be guaranteed in the liberalised electricity markets. In the Nordic electricity market, there is an independent Transmission System Operator (TSO) in every country[7] as a system responsible grid company securing system operation. The amount of disturbance reserve is planned according to dimensioning fault. In the Nordel system, the requirement of disturbance reserve in each country is specified in relation to the largest power unit (Nordel, 2004)[8]. The operational primary reserve is also planned for in the Nordel system, and divided in relation to yearly consumed energy in each country. A common regulating power market is used within the operating hour for balancing (operational secondary reserve).

The frequency control of the synchronous part of Nordel is based on the frequency deviations due to total net imbalances in production and consumption. The TSOs in Sweden and Norway coordinate the task of maintaining the frequency of the whole synchronously operated area during operation. All the TSOs are responsible for activating secondary reserve in their own areas and for ensuring that the physical constraints of the transmission grid are observed (Wibroe et al., 2003).

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[7] The two TSOs in Denmark will merge as of 1.1.2005.
[8] The total amount of disturbance reserve is according to the largest unit in the Nordic countries. This is divided between the countries in relation to the largest unit in each country.

Nordel relies on decentralised production management, so all the producers are either balance responsible players or have a contract with one (or are lower in the hierarchy but always a balance responsible can be tracked). The balance responsible players submit their schedules to TSOs the day before, and can update them up until the hour of operation. The TSOs take over the regulation of the balance during the hour of operation. First, the balance is secured by means of primary reserve (automatic frequency reserve and the instantaneous automatic active disturbance reserve). In the event of major frequency deviation, the TSOs adjust the production or the consumption manually, using secondary reserve through a common regulating power market, 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 primary and secondary reserves.

After the operating hour, the imbalances of the individual players are calculated and these players will be charged or compensated for at regulating power prices realised at the market. The Nordic system is still in the process of moving towards common procedures and the common regulating power market is one step. However, there are still different measures taken in all countries when it comes to balance settlement. In the one-price model used in Norway, the ones having the imbalance in the opposite direction to the system net imbalance gain extra. In a two-price model, the ones whose imbalance is in the opposite direction to the net system imbalance will be paid according the spot market price. This will create an incentive for keeping the balance, and also contribute to the cost of balance settlement. In Denmark and Sweden, the balance is settled separately for production, consumption and trade, whereas in Norway and Finland the balance settlement is for the total balance of the players.

5. Large scale wind power production

The main issues in wind power production from the power system point of view are presented in this chapter: the production patterns (seasonal/diurnal) and the variability, the predictability and correlation with other variable sources of electricity and the varying load. The smoothing effect and representativity of wind power data for power system studies has been dealt with in detail in publication B and the main findings are presented here.

5.1 Production patterns of wind power

(Publication B)

The results of 3 years of hourly wind power production data analyses from publication B are summarised as follows:

- Average yearly wind power production during the example years 2000–2002 is 22–24 % of installed capacity in Denmark, Sweden and Finland and 31–34 % of capacity in Norway.

- Seasonal variation of wind power is clearly present in the Nordic countries, i.e. more production in winter than in summer: 110–140 % of the average in the winter months, 60–80 % of the average in the summer months.

- Wind power production in Denmark and Sweden shows a diurnal variation, more pronounced in summer. In Norway and Finland diurnal variation is present mostly in summertime (Figure 7). The sites in the northern part of Finland, Sweden and Norway do not experience any detectable diurnal variation.

- From the combined production in the Nordic countries, it can be seen that as wind power production comes from geographically distributed wind farms, the total production never reaches the total installed capacity. The minimum production is above 0 as it is never totally calm in all of the Nordic area (Figure 8). Production above 50 % of rated capacity is rare in summer and production above 75 % is rare in winter.

The lowest hourly production was 1.2 % of capacity. The production was below 5 % of capacity about 2 % of the time.

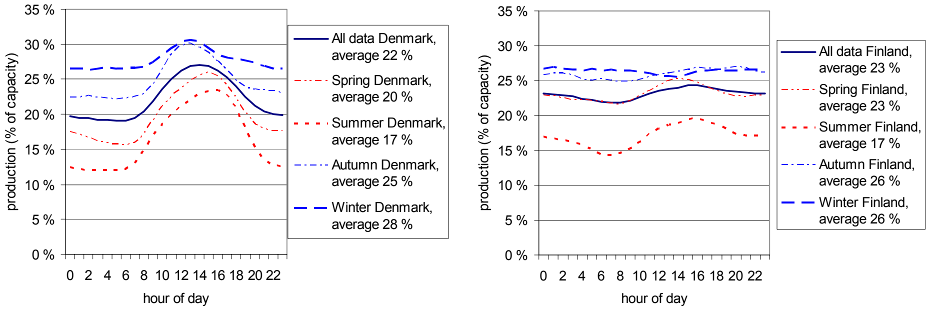


Figure 7. For the Nordic countries, diurnal variation of wind power production is more pronounced in summer time and in the South.

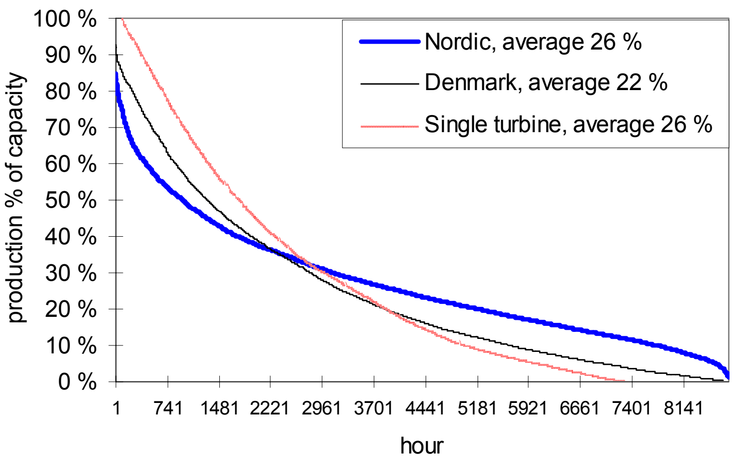


Figure 8. The effect of geographical spreading is to flatten the duration curve of wind power production. Wind energy distributed to all 4 Nordic countries is compared with one of the wind farms and one of the countries (Denmark). Average production for the curves is denoted in the legend text (year 2000 data).

Even for large-scale geographically dispersed wind power production, the production range will still be large compared with other production forms. The maximum production will be three or even four times the average production, depending on the area.

5.2 Variations of wind power production

(Publication B)

For the operation of power systems, the variations from day to day, hour to hour and minute to minute are of interest. For system planning, extreme variations of large-scale wind power production are of importance, together with the probability of the variations.

The in-hour variations are less in magnitude than the hourly variations (Ernst, 1999). The inertia of the large rotating blades of a wind turbine will smooth out the very fast gusts of wind. For a wind farm, the same gusts will not occur simultaneously at all turbines, situated several hundred metres apart. The extreme step changes recorded from one 103 MW wind farm (10 x 14 km^2) are 4–7 % of capacity in a second, 10–14 % of capacity in a minute and 50–60 % of capacity in an hour (Parsons et al., 2001). The ramping rates are not as large as the extreme step changes: maximum 10 s ramping rate (from 1 s data) was 3 % of capacity per second and maximum 10 min ramping rate (from 1 min data) was 6 % of capacity per minute (Wan, 2001). For two large wind farms situated 200 km apart, the extreme step changes are ±1 % of capacity for one second data, ±3 % of capacity for one minute data and ±30 % of capacity for hourly data (Wan, 2001). These examples are from a limited area compared with the system operation. For a larger area of geographically dispersed wind farms, the second and minute variations will be less significant.

There are means to reduce the fast variations of wind power production. Staggered starts and stops from full power as well as reduced (positive) ramp rates could reduce the most extreme fluctuations, in magnitude and frequency, over short time scales (Kristoffersen et al., 2002). This will happen 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.

The results from publication B, for the hourly wind power production time series from the Nordic countries, are summarised as follows:

- Correlation for hourly wind power production is strong (more than 0.7) for distances of less than 100 km and becomes weak (below 0.5) with distances above 200–500 km. The large scale wind power production of the countries is correlated between Denmark and Sweden, and weakly correlated between the other Nordic countries. There is no correlation between the hourly variations in wind power production for the Nordic countries.

- The maximum hourly step changes are inside ± 20 % of installed capacity for one country, somewhat more for Denmark. The hourly step changes in one country are 91–94 % of time between ± 5 % of installed capacity and 99 % of time between ± 10 % of capacity. For the total Nordic time series the hourly step changes are about 98 % of time between ± 5 % of installed capacity (Figure 9). Taking only the time periods when the initial production level is more than the average production, the larger variations occur relatively twice as often.

- The maximum 4-hour-variations are about ± 50 % of installed capacity for one country (for Denmark ± 60 % and for Finland ± 40 %). For the Nordic area it is ± 35 % of installed capacity according to the 3-year data set. This has also been reported for a longer following period from Germany (ISET, 2002). The maximum 12-hour-variation for the Nordic area is ± 50 % of installed capacity (for Denmark ± 80 % and for Finland ± 70 %).

The largest hourly variations are about ± 30 % of installed capacity when the area is in the order of 200 x 200 km^2 (e.g. West/East Denmark), about ± 20 % of capacity when the area is in the order of 400 x 400 km^2 (e.g. Germany; Denmark; Finland; Iowa, US), and about ± 10 % in larger areas covering several countries, e.g. the Nordic countries (ISET, 2002; Milligan & Factor, 2000). For longer time scales, 4–12 h variations, short term prediction tools for wind power give valuable information on the foreseeable production levels and expected variations in wind power production.

For large scale wind power, it is the wind variability that leads to the largest production variations. The stops and starts of the individual power plants during normal operation do not coincide and thus do not impose large variations for large scale wind power when a single turbine is a small part of total capacity (for example, a 2 MW turbine in a country with 1000 MW wind power). The extreme case is a storm when all the turbines are shut down from full power to protect the components. In the case of very large, concentrated offshore installations the chosen cut-out speed for wind turbines as well as control strategies should be applied to avoid situations with large wind power capacity shutting down in an hour (KEMA, 2002). However, large scale wind power is unlikely to materialise in a very concentrated way in the Nordic countries. Based on three years data from Denmark, storms do not seem to hit wind farms in a larger area simultaneously. The wind speeds have not exceeded the cut-off wind speeds for turbines at all sites, as the maximum hourly step change downwards from realised data for West Denmark has been 26 % of installed capacity.

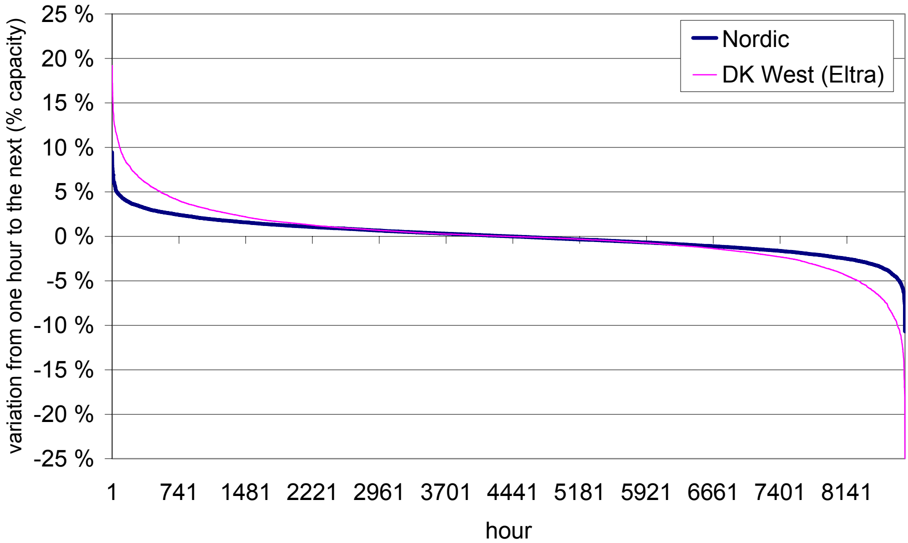


Figure 9. Duration curve for hourly variations of wind power production in West Denmark and in the 4 Nordic countries, assuming an equal amount of wind power in each country.

5.3 Representativity of the variations and smoothing effect

(Publication B)

To be able to up-scale limited wind power production data to large scale production data, the smoothing effect should be incorporated into the time series. When enough turbines from a large enough area are combined, the smoothing effect reaches saturation, and the time series can be up-scaled with representative hourly variations. Guidelines for the statistical properties of large scale wind power were made in publication B:

- To be representative for large-scale wind power production, an hourly time series should have a standard deviation of the production series less than the average power, maximum hourly production less than 100 % of installed capacity (85–95 % depending on how large the area in question is), duration of calms limited or non existent, standard deviation of the hourly variation series less than 3 % of installed capacity and the hourly variations within ±20 % of installed capacity, or even less if the area is larger than the size of Denmark (300 x 300 km^2).

- The clearest indicator of reduced variability in the time series was found to be the standard deviation of the time series for hourly variations. The relative standard deviation for uncorrelated time series will decrease as $1/\sqrt{n}$ (= $n^{-0.5}$) where n is number of data sets. In the case of wind power some correlation exists, however, demonstrated by the results in chapter 5.2. Increasing the radius of the sample size, the standard deviation would follow the relation $\sim x^{-0.244}$ where x is the diameter of the sample area (Figure 10). The standard deviation of the variations is reduced to less than 3 % of installed capacity from a single site value of 10 % of capacity.

- The hourly data collected from about 6 sites in Norway and Sweden represent the range and duration of large scale wind power production. However, when looking at the hourly variations and the decreasing trend of standard deviation with increasing number of wind farms in a larger area (Figure 10), 6 sites is too small a sample to catch the hourly variations, even if the sites are well dispersed over the countries. There will be a slight overestimation of variability for Finnish data (20 sites) when up-scaling the data to large scale wind power production. Combining the data sets of the 4 countries to form a Nordic data set shows a continuing smoothing and has been considered representative for the study of large scale wind power.

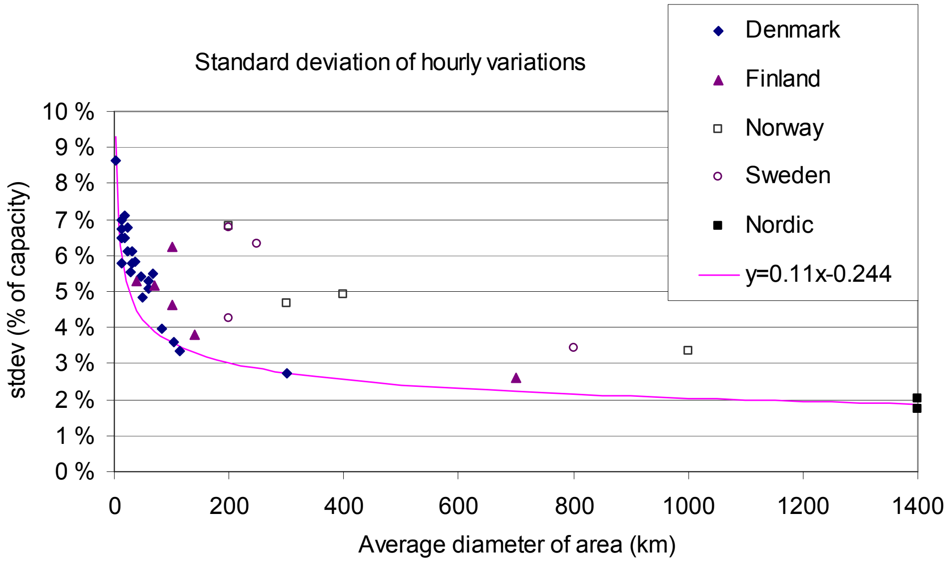


Figure 10. Reduction in variability of wind power production: reduction in standard deviation of hourly variations taken from different areas, 2001 data.

A representative data set for the variations of large-scale wind power could be accomplished simply by collecting time series from different sites until reaching saturation of smoothing effect. After this, the data could be safely up-scaled. In practice, enough data may not be available. In this case, taking sliding averages or weighted sliding averages of wind farm data is one way to smooth it (ILEX, 2003; Persaud et al., 2003). The methodology presented in publication D includes sliding averages of the wind speed time series and the use of a multi-turbine power curve.

The wind power data should also represent the future geographical distribution when simulating the impact of large-scale wind power on the power system. This is taken into account to some extent in this thesis. For example, it is assumed that in Finland 80 % of capacity will be along the West coast and in Sweden 80 % of capacity will be south of Stockholm. In Denmark, there will be fewer turbines and sites but better production from MW-scale turbines with higher towers in the future, especially in offshore wind farms. When a substantial share of wind energy comes from large offshore wind farms this will introduce a less dispersed and thus more variable production, but with higher duration, as there are fewer calms than on shore (Pryor & Barthelmie, 2001).

5.4 Predictability of production

(Publication H)

Wind power prediction plays an important part in the system integration of large-scale wind power. Predictability is stressed at times of high wind power production and for a time horizon of up to 6 hours ahead, giving time to react to varying wind power production. An estimate of the uncertainty, especially the worst-case error, is important information.

Wind power production on an hourly level for 1–2 days ahead is more difficult to predict than other production forms, or the load. The overall shape of the wind power production curve can be predicted using weather forecasts and time series analysis. Predictions of the wind power production 4–8 hours ahead, or longer, rely almost entirely on meteorological forecasts for local wind speeds. In northern Europe, the variations of wind power production correspond to weather systems passing the area causing high winds which then calm down again. The wind speed forecasts of the Numerical Weather Prediction models contribute the largest error component to the wind power predictions. So far, an accuracy of ± 2–3 m/s (so called level error) and ± 3–4 hours (so called phase or time-lag error) has been sufficient for wind speed forecasts. However, the power system requires a more precise knowledge of the wind power production.

Forecast tools for wind power production are still under development and they will improve (Giebel et al., 2003). However, it will probably not be possible to get to the same level of accuracy with wind power predictions as with predictions of the electricity consumption, the load. The load forecasts are made with long experience, and the load has more predictable diurnal and seasonal patterns. When looking at larger areas, the average errors in load forecasts are in the order of about 1.5–3 % of peak load. This corresponds to an error of about 3–5 % of total energy when forecasting one day ahead (Fingrid, 2002).

In publication H, prediction errors for different prediction horizons were studied based on one year of operational data from West Denmark. The predictions are made up to 39 hours ahead and updated half hourly. The results for the prediction errors of 1900 MW wind power are:

- When forecasting 6 hours ahead, the error was within ±100 MW for 61 % of the time. Large errors (> 500 MW) occurred nearly 1 % of the time. When forecasting 36 hours ahead, the errors were within ±100 MW 37 % of the time and large errors (outside ±500 MW) occurred 7 % of the time.

- The proportion of produced energy that will be known x hours beforehand can be seen from Figure 11. Assuming the same level of wind power production ahead as presently (persistence), 90 % of wind power production will be known 1 hour beforehand. From the prediction model, 70 % of the wind power production will be known 9 hours before, 60 % 24 hours before and only 50 % 36 hours before.

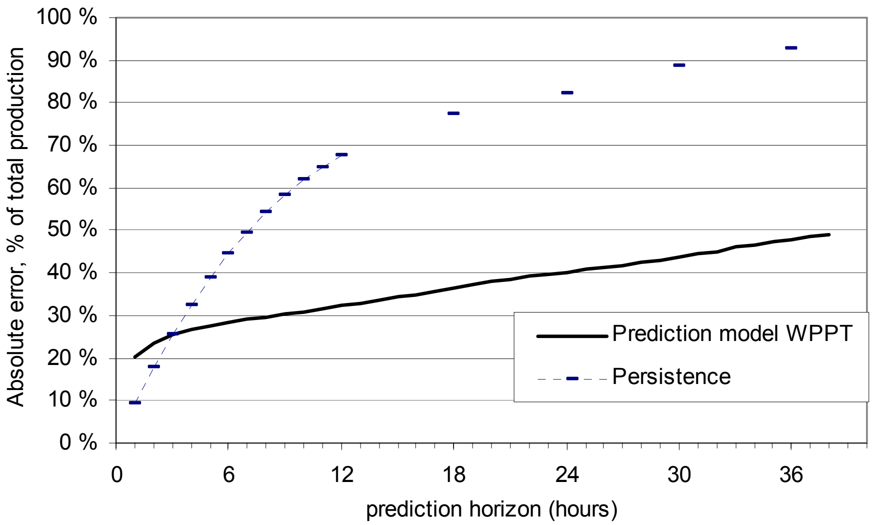


Figure 11. The sum of absolute prediction error for wind power predictions in 2001 for different prediction horizons, as a percentage of the total realised wind power production. Predictions from the model Wind Power Prediction Tool (WPPT) are from on-line runs during the year.

- For the Nordpool electricity market (prediction horizon 13–37 hours ahead), the mean absolute error (MAE) of wind power prediction is 8–9 % of installed capacity. However, for market operation it is relevant to know the error in the amount of energy produced, and this is 38 % of the yearly wind power production.

- The decrease in prediction errors for larger areas was analysed from one year data for Denmark. Including East Denmark adds 100 km or 50 % to West Denmark's area, in the direction in which most weather systems pass (West–East). For about a third of the time production is overpredicted in the West and underpredicted in the East, or vice versa, resulting in errors canceling each other out to some extent. The total prediction error is reduced by 9 %. If East Denmark would have the same amount of wind power capacity as West Denmark, the reduction in prediction error would be 14 %, according to 2001 data.

It has to be noted, improvements in wind power prediction are expected in the future and the results reported here are not from the latest state-of-the-art prediction models, as explained in more detail in Publication H.

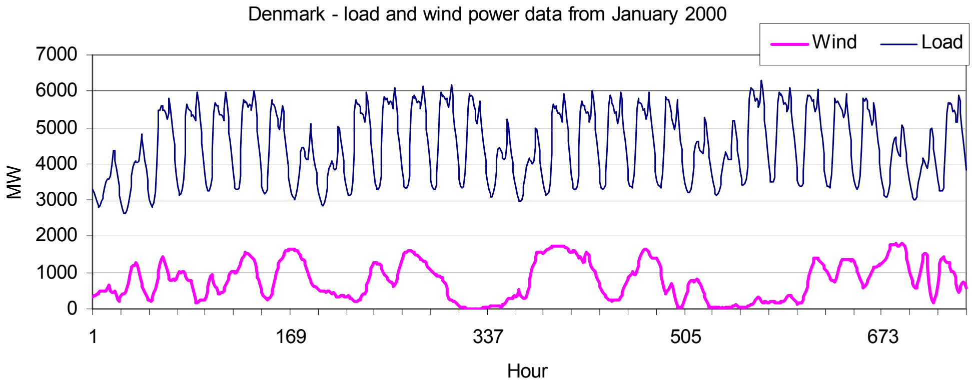
5.5 Correlation of load, wind power and other variable energy sources

(Publication C)

The correlation between wind power production and electrical load is of importance when considering the power system effects of a variable production form such as wind power.

The electrical load is characterised by a daily and hourly pattern which is higher on weekdays than weekends (Figure 12). In addition to daily cycles, strong temperature dependence can be seen in the Nordic countries. In Denmark, also wind strength is taken into account in forecasting the heat demand. In the Nordic data, there is a slight positive correlation between wind power production and load (Denmark 0.21; Finland 0.16; Norway 0.37; Sweden 0.24; Nordic 0.31). However, when looking at the winter months only, the correlation is near zero. The positive correlation comes from the diurnal pattern of wind power mostly present in summertime.

Even simple statistical independence makes different variable sources more valuable than just more of the same. When variable sources are directly complimentary, e.g. wind and solar in the same location, there may be large benefits. Also, combining variable sources with energy limited plants can be beneficial. For the Nordic countries, an interesting example is hydro power. Even if dry years are not likely to be high wind years, as the correlation between the yearly wind power production and hydro inflow is zero or positive in the Nordic countries, the monthly and weekly distribution over the year is quite beneficial. Hydro inflow has a peak in May/June in the Nordic countries, whereas wind power production is dominant in wintertime (October–February). Studies in Sweden and Norway show that wind power production combined with hydro power brings benefits for the system (Söder, 1999; Tande & Vogstad, 1999).



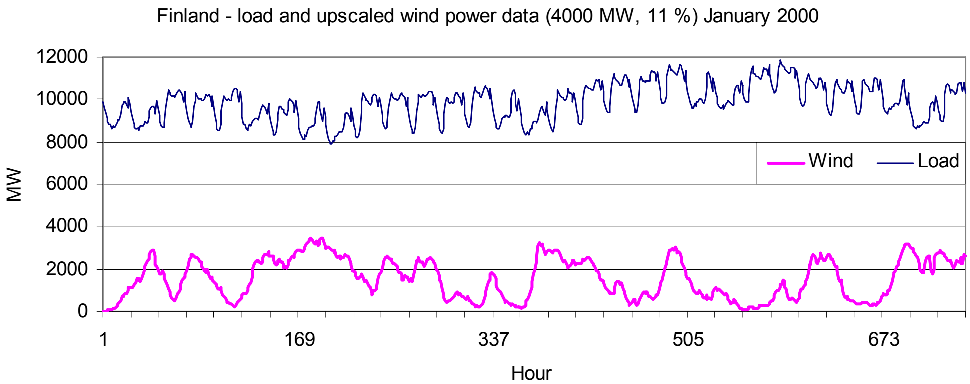


Figure 12. Electricity consumption (load) and wind power production in January 2000. Denmark is real data (12 % wind power). Finland data comes from scaling up wind farm data to a wind power penetration of about 11 % of yearly gross demand.

Correlation between wind power production and the temperature dependent district heating CHP production is only slightly positive for Denmark (0.14–0.24) and Finland (0.17–0.27). For wintertime, again the correlation is nearly zero.

6. Short term effects of wind power on the power system

In this chapter, the impact of wind power on the power system on a minutes-to-hours time scale are discussed. The impacts are divided into two parts: the operating reserves and the production/transmission. This division reflects the working of the power system: even if the reserves are mostly provided by the production units, the operation as reserve, moving the production up and down as required for the total balance, is different from the energy production function of power plants.

First, the reserve needs due to wind power are discussed, and the estimate in publication C is extended to include a cost estimate. The effects on the production of the rest of the production capacity – cyclic losses, increased transmission between the areas, replaced production and reduced emissions are described, in the light of simulations made in Publications E, F and G. The chapter ends with a discussion about the modelling of wind power with the existing dispatch/simulation models.

6.1 Operating reserve requirements for wind power

Dimensioning of the disturbance reserve in each Nordic country is based on the largest production unit tripping off instantaneously. In addition operational reserve is also needed in power systems. Wind power has no influence on the disturbance reserve as long as wind farms are less than the largest production unit in the system (1200 MW in 2004)[8].

The impacts of wind power on requirements and costs of balancing the system on the operational time scale (from several minutes to several hours) are primarily due to the fluctuations in power output generated from wind. In the Elbas market, the players can trade up to one hour before delivery. For Finland and Sweden, bilateral trading can take place up to 20 minutes before the delivery hour. In Norway, generation plans can be changed within a balance area up till the time of delivery if this is accepted by the TSO. Operation and balancing of the system is left to the TSOs during the operating hour. This is what the operational reserves and the regulating power market are used for.

To estimate the impact of wind power on power system operating reserves, it has to be studied on a control 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. It is the total system aggregation, from all production units and consumption, that has to be balanced. A producer with flexible production could in principle counteract changes in wind power levels also during the operational hour. Self regulation is discouraged, however, as it is more cost effective for both the system and the individual players to bid all regulating power to a joint pool for the TSO to use the cheapest options first.

6.1.1 Primary reserve

Primary control is performed on a time scale of seconds/minutes. On this time scale, variations are already smoothed by different gusts for the individual turbines, inertia of the large rotors as well as variable speed turbines absorbing the variations, and there is no correlation between the variations of geographically dispersed wind farms (Ernst, 1999). The effect of wind power on the system operation in the primary control time scale is very small even at considerable penetration (Ernst, 1999; Kirby et al., 2003; Dany, 2001).

A rough estimate of the effects of large-scale wind power on the primary reserve assumes that increase in wind power and its variations requires the same addition to reserves as the increase in electricity demand and its variations (Holttinen & Hirvonen, 2000). The primary reserve has been 600 MW for 360 TWh/a demand in the synchronously operated Nordic area (Nordel, 2004). Assuming an increase relative to how much variable consumption there is, producing 10 % of the demand with wind power (36 TWh/a; 18 GW wind power) would increase the primary reserve by 10 %. This means an increase of 60 MW or about 0.3 % of the wind power capacity installed. This estimation gives order of magnitude only, based on earlier experience on the amount of primary reserve needed in the system. Actually the same 600 MW has been the amount of primary reserves for more than 10 years, with gross demand below 300 TWh/a. The primary reserve requirement is based on second/minute values of power, not the (yearly) energy.

6.1.2 Secondary reserve

(Publication C)

For operational reserves, the unforeseen variations induced from wind power are relevant on the time scale of 10 min – 1 hour. In the Nordic system, there is no operational secondary reserve defined any more, after the regulating power market was started. Norway and Sweden have agreed to coordinate the frequency control and activation of reserves from the regulating power market according to net balance in the Nordic synchronous area.

In publication C, wind power variations are studied combined with the load variations: the net load is the load minus the wind power production for each hour. In Figure 13, the extent of hourly variations are depicted, without wind (the hourly variations of the load) and with wind (the hourly variations of net load). The difference in the maximum value indicates the amount that the operating reserve capacity has to be increased. The difference in the duration curves indicates the amount that the existing reserve capacity is operating more when wind power is added.

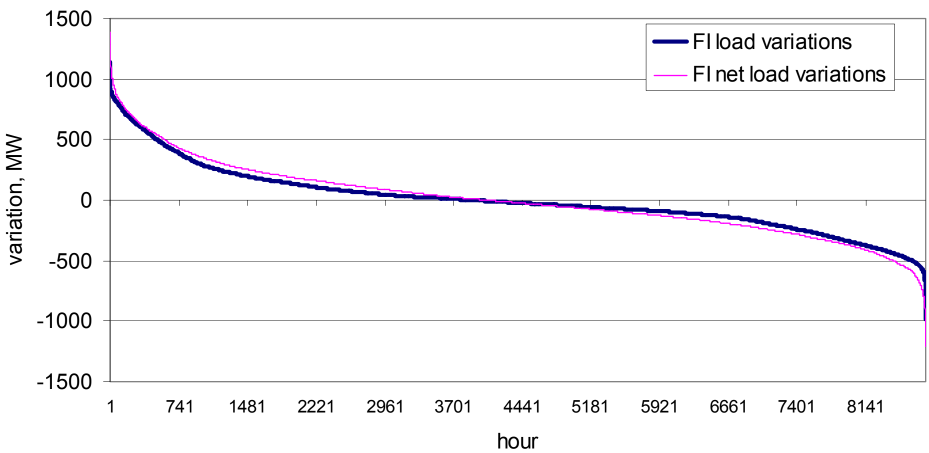


Figure 13. Duration curves of load variations without wind power and net load variations with wind power. The case is for Finland in the year 2000 with hypothetical 6000 MW wind (17 % of gross demand).

The increase in reserve requirement due to wind power was estimated using a statistical approach. Planning and operating a power system is based on probabilities and risk. Reserves in the power system are determined so that variations within a certain probability are covered, for example 99.99 % of the variations. Standard deviation σ indicates the variability of the hourly time series: for a normally distributed probability distribution a range of ±3σ will cover 99 % and ±4σ will cover 99.99 % of all variations. In this work, 4σ is used as a confidence level to determine the amount of reserves that need to be allocated in the power system. The increase in the variations due to wind power is $4(\sigma_{NL} - \sigma_L)$, where σ_{NL} is the standard deviation for the net load and σ_L for the load, respectively.

Calculating the increase in variability this way assumes that wind power only contributes to the reserve requirement by the increase due to its addition to the system. This means that wind power can make use of the benefits of the existing power system. In the USA, different allocation methods for joining two varying elements have been elaborated (Kirby & Hirst, 2000) where the benefit is divided by the two. In this case, the system would benefit a part of the addition of wind power and the impact of wind power would be more than the simple increase in variations calculated here. Both methods are numerically correct. The difference in these approaches is in the fairness or design of regulation payments. In the Nordic countries, different loads and production units do not pay different tariffs for the regulation burden they pose to the system. Thus it is justified to calculate only the simple addition to reserve requirements for wind power.

To account for the better predictability of load (Milligan, 2003), a case study for Finland was performed for year 2001 load data with load forecasts. The standard deviation of the forecast error was 123 MW (1 % of peak load), in comparison with 268 MW for the load hourly variations. This indicates that about half of the variability in load can be predicted. Comparing the load forecast error with wind power variations resulted in a 100 % increase in net load variations. The results of Publication C are summarised in Table 1 and Figure 14. As Denmark consists in practice of two separate areas, the West Denmark results are also of interest. They are roughly the same as the results presented here for Denmark.

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 variations. For the Danish data, the error was estimated to be of the order of 5 %, and it has been added to the results in Figure 14 in the last section of Table 1.

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 variations 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 less or more concentrated wind power capacity in the Nordic countries.

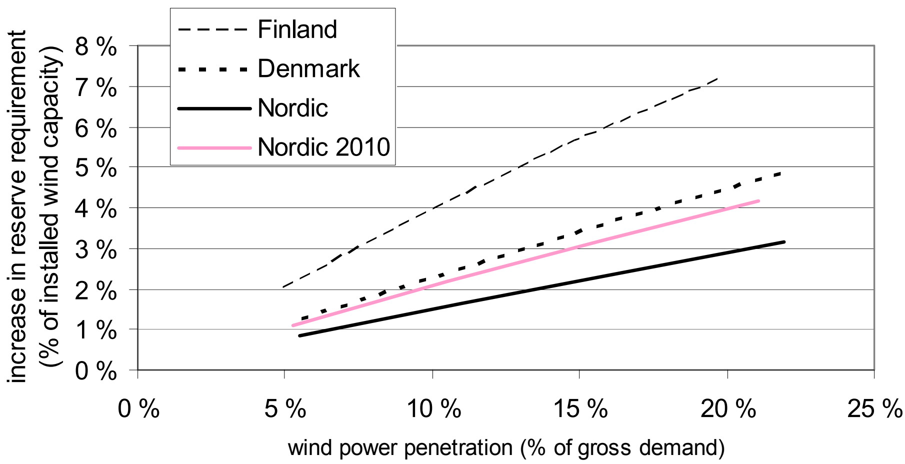


Figure 14. Increase in hourly load following requirement for wind power, calculated from the standard deviation values of load and wind power production from years 2000–2002. Increase is relative to installed wind power capacity.

These estimates present a theoretical approach for estimating the order of magnitude of the effects of wind power variability on the system operation. As the total Nordic balance is handled at a common regulating market, the true estimate would require data for the total load and production schedules for the whole Nordic area. The variations in wind power production are probably still somewhat conservative for Finland and the total Nordic area, as the smoothing effect of thousands of wind turbines at hundreds of wind farm sites is underestimated by the data sets used. It has been assumed that the hourly variations give an estimate of the secondary reserve operated on a 10–15 minutes scale. As the wind power varies less within an hour than on an hourly basis, using hourly data would not underestimate the effects. The results from a study for Northern Ireland suggest that, at a 10 % penetration, the increase in hourly variations in the net load 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).

Table 1. The increase in reserve requirement due to wind power with different penetration levels. Statistical analysis of hourly data for wind power and load in the Nordic countries for 2000–2002. The range in Nordic figures assumes that the installed wind power capacity is more or less concentrated.

	Finland		Denmark		Nordic	
	MW	% of peak load or capacity	MW	% of peak load or capacity	MW	% of peak load or capacity
Range of hourly variations*:						
- Load	-985–1144	-7.2–8.4	-862–1141	-13.7–18.1	-5138–6698	-7.6–9.9
- Wind		-15.7–16.2		-23.1–20.1		-10.7–11.7
Stdev of hourly variations:						
- Load	268	2.0 %	273	4.3 %	1438	2.1 %
- Wind		2.6 %		2.9 %		1.8 %
Increase in variations (4σ), 2000–2002 data:						
- 5 % penetration	20	1.0 %	6	0.6 %	40–55	0.4–0.6 %
- 10 % penetration	80	2.0 %	24	1.2 %	155–210	0.8–1.1 %
- 20 % penetration	285	3.6 %	94	2.4 %	600–800	1.6–2.1 %
Increase in reserve requirements:						
- 5 % penetration	40	2.0 %	13	1.3 %	80–110	0.8–1.2 %
- 10 % penetration	160	3.9 %	50	2.5 %	310–420	1.6–2.2 %
- 20 % penetration	570	7.2 %	200	4.9 %	1200–1400	3.1–4.2 %

*The hourly load variations are 99 % of the time between -7.2–16 % of peak load in Denmark, -4–6.6 % of peak load in Finland and -4.4–7.4 % of peak load in the total Nordic time series. The hourly variations of large scale wind power production are 99 % of the time between ± 10 % of installed capacity for Finland and Denmark and about 98 % of the time between ± 5 % of installed capacity for the total Nordic time series.

The prediction errors of wind power day-ahead may also be seen at the system net imbalance and thus require extra balancing at the regulating power market. The increased balancing requirements would be seen either as changes of schedules at the balance responsible players responsible for wind power production, or as individual imbalances that might affect the system net imbalance. This is further discussed in chapter 8.

6.1.3 Cost of increase in reserve requirement

Both the allocation and the actual use of reserves cause extra costs. The same reserve capacity can in principle be used for both up and down regulation. Either up or down variations can determine the need for increase in the reserves. In most cases, the increase in reserve requirements at a low wind power penetration could be handled by the existing capacity. This means that only the increased use of dedicated reserves or increased part-load plant requirement will cause extra costs. Beyond a threshold, the capacity cost of reserves also has to be included. In the Nordic countries this threshold depends on whether there is still capacity available to bid to regulating power market.

Regulation power costs more than the bulk power available on the market. The reason is that it is used during short intervals only and that it has to be kept on stand-by. Therefore, any power continuously produced by this capacity cannot be sold to the electricity spot market. The cost of reserves depends on the type of production. Hydro power is the cheapest option and gas turbines are a more expensive one.

In the following, the cost of increased reserve requirement due to wind power is estimated. The cost of increased regulation in the hydro power system is difficult to obtain. Thus, the cost is estimated in two ways: based on thermal capacity costs and on existing regulating power market prices. The cost estimates for thermal capacity include the price for new reserve capacity and assume a price for the use of the reserve.

Primary reserve is not assumed to cause extra costs for wind power penetration levels below 10 %. The cost of an extra 60 MW in the Nordic synchronous area, for 36 TWh/a wind power production producing 10 % of the gross demand, is the price for reimbursing the power plants for using automatic frequency control. This is paid irrespective of the use, for all the hours the reserve is allocated. Using the payments in place in Finland (3.3 €/MWh and a fixed payment of 7500 € per MW; Fingrid, 2004), the primary reserve cost for 10 % wind power penetration would be less than 0.1 €/MWh of wind power produced. An increase of 60 MW in reserve requirement is conservative, as the total 600 MW has been in use in the Nordic countries for years, irrespective of the load increase. It seems that there is not a linear relationship between the reserve allocation and the amount of total consumption in the system, as the same 600 MW requirement has been in place for more than 10 years.

The estimate made in publication C for the increase in reserve requirement due to wind power is the need for new capacity with a 4σ confidence level. In the case of the Nordic countries, this amounts to 310–420 MW at a 10 % wind power penetration and 1200–1400 MW at 20 % penetration (Table 1), depending on how concentrated the installed wind capacity will be. The corresponding costs can be estimated by increasing flexible natural gas combined cycle (NGCC) gas turbines in the power system (investment cost 505 €/kW). Dividing the annualised costs of NGCC (a=13 %) to the wind power production results in a cost of 0.5–0.7 €/MWh at 10 % penetration and 1.0–1.3 €/MWh at 20 % penetration level.

In addition to the increase in allocated regulation capacity, there is the actual use of the capacity causing reserve power costs. The amount of increased use as MWh can be seen from the duration curves of load and net load variations (example in Figure 13). For the Nordic countries, this amounts to 0.33 TWh/a and 1.15 TWh/a, respectively. To account for the better predictability of load variations, these amounts have been doubled. For Finland, load forecast time series was available, and the increase in variations was 0.28 TWh/a at 10 % penetration and 0.81 TWh/a for 20 % penetration.

The relevant reserve cost for wind power is determined by the Nordic regulating power market. The extra paid for regulation is the difference between the spot price and the regulating market price. This has been on average 4–5 €/MWh for up regulation and 5–9 €/MWh for down regulation in Finland, and 6–8 €/MWh up and 10–15 €/MWh down in West Denmark in 2001–2003. The increased cost of thermal capacity for operating at secondary reserve has been assumed as 8 €/MWh (Milborrow, 2001), so the market prices are in line with the actual costs.

Assuming a price range of 5–15 €/MWh for the extra reserve used, the cost of increase regulation need in Finland is 0.2–0.5 €/MWh wind power produced at a 10 % wind penetration level and 0.3–0.8 €/MWh at 20 % penetration For the Nordic dataset, the cost is 0.1–0.2 €/MWh for 10 % penetration and 0.2–0.5 €/MWh for 20 % penetration, respectively.

Since the opening of a common regulating power market, most of the reserve power activated has been from Norway and Sweden, with the lowest bids from the large regulated hydro plants. There seems to be ample capacity bidding to the regulating power market (Lehikoinen, 2003). It is thus unlikely that an increase in wind power would result in new reserve capacity being built. However, it is quite likely that a major increase in wind power would result in an increase in the regulating market price. In a situation where the cheapest regulation bids have already been used and more expensive regulation has to be allocated, the costs of regulation may rise substantially and suddenly. This is why the historical prices can be used to estimate the costs only as long as the regulation amounts needed are such that the regulating capacity bidding to the market has a similar price. In West Denmark with 16–20 % wind power penetration, the down regulation costs have increased 50 % but no other changes have been observed. With the cost range presented here, the higher estimate of 15 €/MWh accounts for doubled regulation market prices due to wind power.

In conclusion, the cost of increased operating reserves in the Nordic power system will be 0.7 €/MWh for the allocation of capacity and 0.2 €/MWh for the use of the reserves, or a total of nearly 1 €/MWh for a 10 % penetration. For a 20 % penetration we have 1.3 €/MWh plus 0.5 €/MWh respectively, or a total of nearly 2 €/MWh for 20 % penetration. These costs would be halved if the conservative estimate for allocating investment costs for new reserve capacity to the wind power production is replaced by the increased use of reserves only.

To integrate wind power into the power system in an optimal way requires use of the characteristics and flexibility of all production units, so that a total system optimum is reached. In addition there are already existing technologies that could be used to absorb more variable energy sources such as Demand-Side-Management (DSM), increased transmission between the areas and electrical or thermal storages in the power system. Also wind farms can provide down regulation to a certain extent.

6.2 The impact of wind power on electricity production and transmission

6.2.1 Replaced energy and reduced emissions

(Publications E, F and G)

The electricity supplied by wind power is CO_2 free. Taking into account the materials and construction of wind farms, the CO_2 emissions are of the order of 10 gCO_2/kWh (Lenzen and Munksgaard, 2002).

The amount of CO_2 that will be abated depends on what production type and fuel is replaced when wind power is produced. Both in regulated and deregulated electricity systems, the use of the production form with highest marginal cost will be lowered by wind energy. Wind energy often replaces electricity from old coal fired plants, resulting in a CO_2 abatement of about 800–900 gCO_2/kWh. This is true for most systems with some coal fired production plants, when wind energy provides a minor amount of the total electricity consumption. This is a good estimate for the CO_2 reduction when introducing wind power in a country. This is also valid for large amounts of wind, for the countries where electricity production is based on coal. For other conditions, wind energy may replace gas fired production (400–600 gCO_2/kWh), or even CO_2 free production forms such as hydro, biomass or nuclear power. Even if the hydro production is reduced by wind energy, the hydro power stored in the reservoirs may be used later, possibly reducing fossil fuel fired production. Interconnected systems can also respond in such a way that wind power is partly replacing coal fired production in a neighbouring country.

The simulations made in this thesis reveal the replaced energy and fossil fuel savings due to wind energy. The results indicate that in the Nordic countries, wind power will replace production in condensing power plants, mostly in coal fired plants, resulting in CO_2 abatement of 620–700 gCO_2/kWh wind power produced. The exact result depends on the amount of wind power in the power system, and on the amount and costs of coal and gas fired production in the system.

If the use of coal-condensing power were to be prohibited in Finland, new wind power capacity would mainly replace other condensing power capacity, most likely natural gas combined-cycle (NGCC) capacity. In this case, the average CO_2 reduction would be about 300 gCO_2/kWh, due to the high efficiency of NGCC and other small changes in the energy system. It should be noticed that in this scenario part of the wind power potential would be used already in the basic cost-optimal case, against which the wind cases are compared, and so this is the result of an extra increase in wind production to the system. This case reflects the situation in the future, when there is possibly no more coal to be replaced.

The results for the Nordic electricity system and the Finnish energy system are based on assumptions that the wind energy is already in the system, and there are no extra costs due to in-week variability of wind. The more detailed simulation for the West Denmark energy system includes the extra operational costs of thermal power. If all wind energy is used within West Denmark, it will decrease mostly coal and gas power, but at high penetrations effects on other renewables can also be seen. The first 10 % share of wind power shows a 450 g CO_2/kWh reduction. Going from a 30 to a 40 % penetration level would result in a lower abatement, or 350 gCO_2/kWh. When the possibility for electricity transmission outside West Denmark is included, and the reduction in fuel use is calculated in West Denmark only, the emission reduction is 50–200 g/kWh, mainly due to the added exports of electricity.

The cost of wind power as a CO_2 reducing technology could be calculated from the Finnish energy system simulations. In the scenario where wind energy would be 1 TWh/a in 2010, the average emission reduction cost during 2010–2025 was about 20 €/t CO_2 (wind power penetration 1–6 % of gross demand). When the wind power capacity is further increased, the average cost will rise gradually to about 35 €/t CO_2. This is quite an obvious result because at first wind power replaces the most expensive condensing power capacity and after that the replacement is aimed at less expensive capacity.

According to simulations reported in publication G, wind power production in Norway and Sweden would mostly reduce emissions elsewhere in the interconnected market area. This also means that the CO_2 emission benefits of wind power would partly materialise in a country other than where the wind power is installed. The interactions of the electricity market with Tradable

Emission Permits (TEP) and Tradable Green Certificate (TGC) markets have been ambiguous for the energy policy makers – it is not a straightforward relationship between the quotas and prices set by policy makers and the resulting emission savings (Jensen and Skytte, 2002; Nese, 2002). There might be problems, especially with international trade of TGCs: as the CO_2 benefit is not tied into TGC, the country where it is most cost effective to build the renewable production will benefit from the CO_2 reductions, paid for by other countries (Jensen and Skytte, 2002; Nese, 2002).

6.2.2 The impact of wind power on thermal power scheduling

(Publication E)

Optimised unit commitment, i.e. planning the starts and shutdowns of slow-start units, is more complicated when the intermittent output from wind power is included. Large variations in wind power output can result in operating conventional power plants less efficiently. If wind power production exceeds the amount that can be absorbed while maintaining adequate reserve and dynamic control of the system, a part of the wind energy produced may need to be cut off.

The effect of wind power on existing thermal units can be estimated by simulating the system on an hourly basis. In publication E, the West Denmark power system was simulated with SIVAEL model, increasing wind power using different transmission possibilities (no/low/high) and market prices (low/high).

The main findings of SIVAEL simulations for West Denmark are summarised as follows:

- Increased exchange between West Denmark and the neighbouring countries was 50–90 % of the wind energy produced in the region in most cases.

- Increase in the starts and stops of the thermal plants could only be seen in the simulation results when looking at the system without transmission possibilities. Allocating the extra start/stop costs to wind power added 0.6 €/MWh for the first 10 % of wind power and 0.5 €/MWh for the first 20 % of wind power, respectively. Having more than 20 % of wind power in the system resulted in increased part load operation of thermal plants, and thus the starts and stops were reduced.

- The increased penetration of wind power resulted in an increase in the cost of power produced by the system of 4 €/MWh at a 40 % penetration (allocating the cost to wind power production). This is the result for the power system operating without exchange, and it was derived from the value of wind energy as reducing fuel costs in the power system (19 €/MWh at a 10 % penetration, and 15 €/MWh at a 40 % penetration).

- If no electricity transmission was allowed from the region, surplus power (discarded energy) occurred from a 20 % wind power penetration onwards. When high transmission of electricity was allowed, the surplus problem first arose at a 50 % wind power penetration.

- The regulation burden due to the prediction errors of wind power was simulated separately, not aggregating with total power system balance. When simulating the West Denmark area without exchange, the extra regulation requirement due to wind power will result in increased discarded (surplus) energy. In the case of a 10 % share of wind energy, 20 % of the down-regulation needs result in a surplus of energy and 10 % of the up-regulation needs would result in a deficit of energy, showing an increasing trend with increasing penetration. With electricity exchange possibilities, the thermal power plants in West Denmark would be used for about half of the up-regulation needs but only about 10 % of the down-regulation needs, and the rest would come from the electricity exchange. Increasing the wind power penetration level would mean using more exchange for up-regulation and less for down-regulation.

6.2.3 The impact of wind power on hydro power scheduling

(Publication F)

The results from the EMPS simulations on the changes in hydro power production from increased wind power production are summarised:

- Wind power may influence the reservoir contents and reservoir management. Figure 15 demonstrates the average content of the reservoirs in Northern Sweden, as well as minimum and maximum during each week, over 30 years. When the wind production is large compared to the reservoir size in the area, such as in Finland, there is a clear effect on reservoir management (Figure 16). The largest changes in reservoir management were seen in Finland and North Norway (Finnmark), where wind power production was increased to more than the total reservoir content of the area.

- Wind power may also influence the losses of hydro power production. For example, a large wind power production in the spring flood time can result in the loss of some hydro production. In the Nordic power system with 46 TWh/a wind production (12 % penetration), the losses due to increased floods were 0.5–0.6 TWh/a, which is about 1 % of the wind power production.

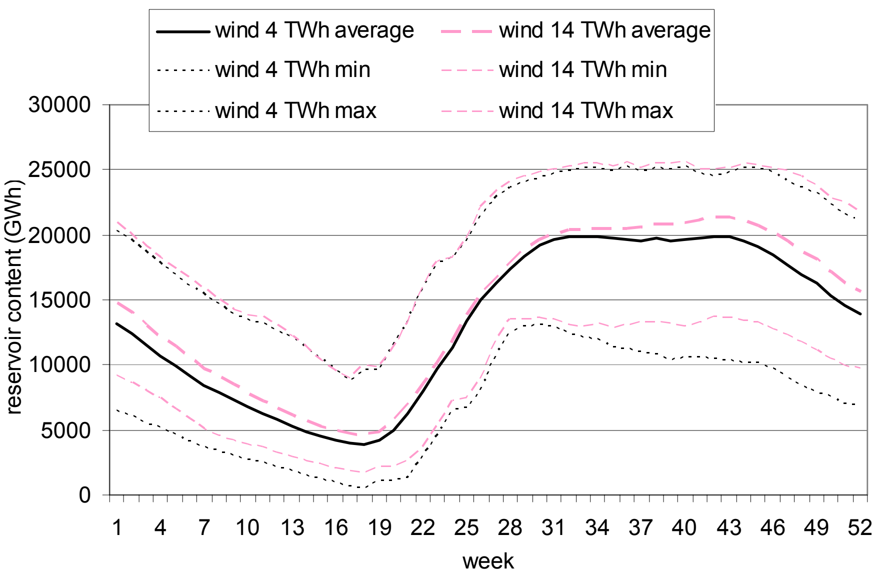


Figure 15. Simulated contents of the hydro power reservoirs in North Sweden when the amount of wind energy in Sweden is increased from 4 to 14 TWh/a and in the Nordic countries from 16 to 46 TWh/a (average, minimum and maximum content over 30 years).

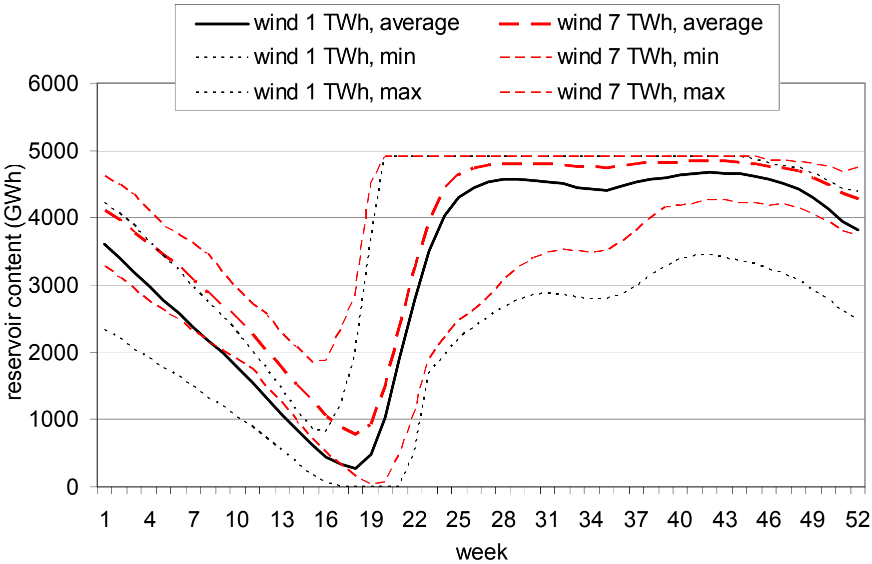


Figure 16. Simulated contents of the hydro power reservoirs in Finland when the amount of wind energy in Sweden is increased from 1 to 7 TWh/a and in the Nordic countries from 16 to 46 TWh/a (average, minimum and maximum content over 30 years).

The impact on the value of hydro power produced will depend on how wind power will affect the market prices discussed more in chapter 8. Hydro power is also providing regulating power for which the demand will grow with higher penetration of wind power.

The simulations made here cannot assess the impacts that the wind power may have on the short-term operation of hydro power where unit commitment is an important issue and where the scheduling horizon must cover 10–14 days ahead in well regulated hydro reservoir systems.

6.2.4 The impact of wind power on the transmission between the areas

(Publications E and G)

The simulations made for the whole Nordic area and West Denmark showed that an increase in wind power in the power system resulted in an increase of electricity transmission between the countries and regions.

The SIVAEL simulations indicate that 50–90 % of the wind energy in West Denmark is exported in different cases for price levels and electricity exchange possibilities. At the border of two regional power systems a huge transit of power is observed in certain situations. When transmission to Germany is available, this will increase both the imports and exports, as there will be transit of electricity through Denmark from the hydro power dominated Nordic countries to the thermal power system in Germany and vice versa. The exception is the case of a high price level and transmission availability to Nordic countries only. If a dry year in Norway and Sweden occurred this would result in an increased price level and export of thermal power from West Denmark, even if wind power was increased in West Denmark. In this case most of the wind power would reside in West Denmark.

The EMPS simulations for the Nordic area show that about half of the wind power production in the Nordic countries would be exported to Central Europe. For a 8–12 % penetration of wind power, indications of bottlenecks in transmission in all lines to Central Europe were seen, especially from West Denmark to Germany. Between Norway and Denmark, Norway and Sweden, and within Norway, wind production would ease dry year conditions but strengthen some bottlenecks during wet years. High wind production in northern Norway would create a bottleneck in the weak transmission line between northern Norway and Finland. Between Sweden and Finland and inside Sweden even large-scale wind production may not substantially increase the use of transmission lines compared to the reference situations.

The results presented here are theoretical cases, assuming that the remaining electricity system is static while increasing the share of wind power. The general conclusion can be drawn that using the models with a large buffer with transmission capacity (Germany in the Nordic models), simulations end with increased transmission instead of dealing with the variability in the area where wind power is installed. This supports the observation that in many cases the most effective way of integrating wind power is to increase transmission capacity, or deal with the bottleneck situations (Matevosyan, 2004). The results may overestimate the effect of increased exports, however. To see how much the exports were due to overcapacity due to increased wind power, simulations with EMPS were performed, reducing conventional condense capacity while increasing wind power. This showed lower net exports to Central Europe, about 10 % of the wind power produced.

6.2.5 Discussion on the modelling of wind power

The models used here are not specifically designed for dealing with high shares of wind power. Some remarks on their restrictions have been made in chapter 3.

For wind power impact on the operating of power systems, modelling on an hourly level would be needed to catch the variability of wind. From weekly simulations, the assumption that the hydro system can handle the in-week variations of wind power can be feasible for Norway and perhaps also for Sweden. It leaves, however, doubts regarding the effects of wind variability on the system.

The effects of wind power on a power system are spread over the total control area (synchronously operated area) or electricity market, with constraints on transmission capacities between the areas. Effects of wind power are first seen as an increase in exchange of electricity between the areas. The results will, however, show only increase in transmission unless boundary conditions are set, to be able to see the limits to the transfer of wind power variability to the neighbouring areas. Contingencies, due to dynamic phenomena, cannot be modelled with an hourly time scale model. Due to this, the low transmission possibility scenario is often used, and this can underestimate the exchange possibilities during most of the time.

Modelling the effect of prediction errors is complicated by the uncertainties to different time scales of unit commitment (starting and shutting down slow thermal units) and dispatch (production levels of thermal units). Problems can also emerge from the simulation logic in itself: optimisation of the system can be fundamentally different if taking into account the different nature of wind power production. Also, regulation requirements are often not modelled directly, but based on years of operating experience, so the effect of wind power cannot be modelled either (Dragoon & Milligan, 2003). Electricity market interactions and price levels should also be looked at when simulating wind power in the system.

7. Long term effects of wind power on the power system

The power system has to serve electricity consumption with a low probability of failure. The economic costs of failing to provide adequate capacity to meet electricity demand are so high that power companies have traditionally been reluctant to rely on intermittent resources for capacity. The 3–4 years of hourly wind power and load data collected for this thesis has been analysed to investigate wind power production during high electricity demand situations (Holttinen, 2003).

7.1 Temperature dependence of wind power

In Northern Europe, the electricity demand is strongly correlated to the ambient temperature. The correlation between wind power production and temperature has an effect on the adequacy of power production when determining the capacity value of wind power.

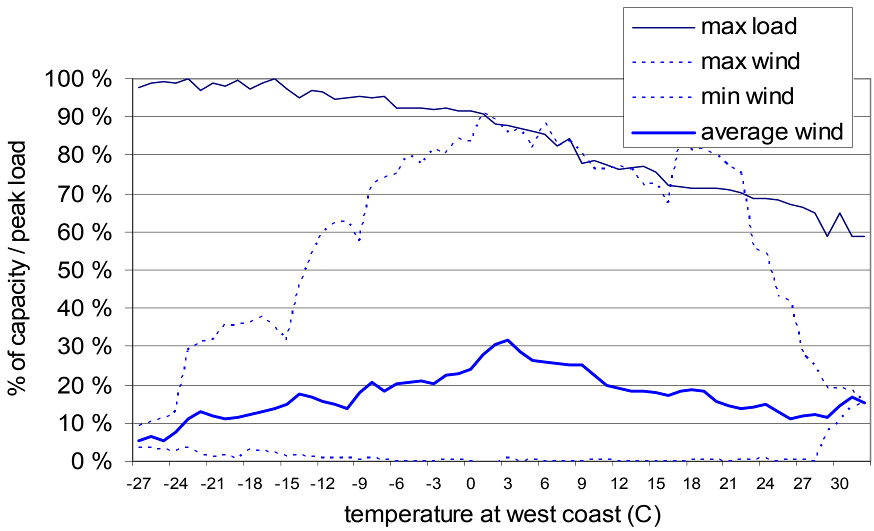


Figure 17. Temperature dependence of wind power production and load in Finland (1999–2002). The average wind power production was 22 % of capacity. There were 549 hours (1.6 % of time) below –14°C.

The average wind power production at low temperatures of below –15°C is somewhat lower than the yearly average wind power production in Finland, and these are the incidents of highest load (Figure 17). Similar behaviour can be seen in Denmark (Figure 18). The average wind power production in the total Nordic wind power time series does not show this kind of reduction (Figure 19).

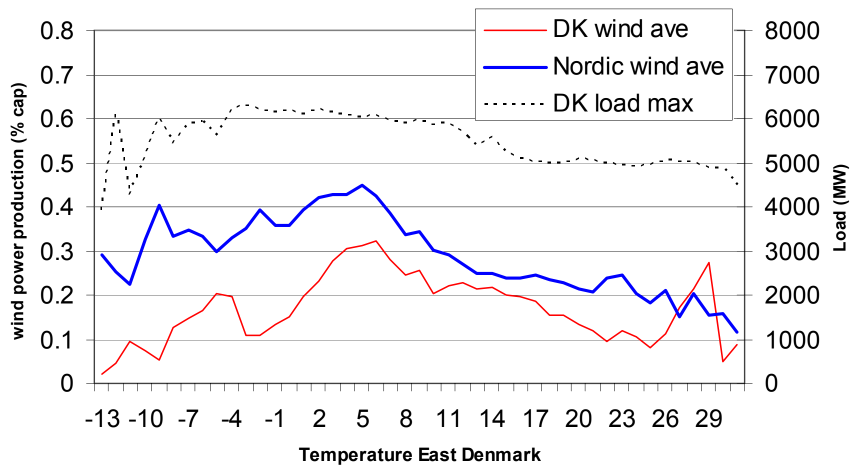


Figure 18. Temperature dependence of wind power production and load in Denmark (2000–2001).

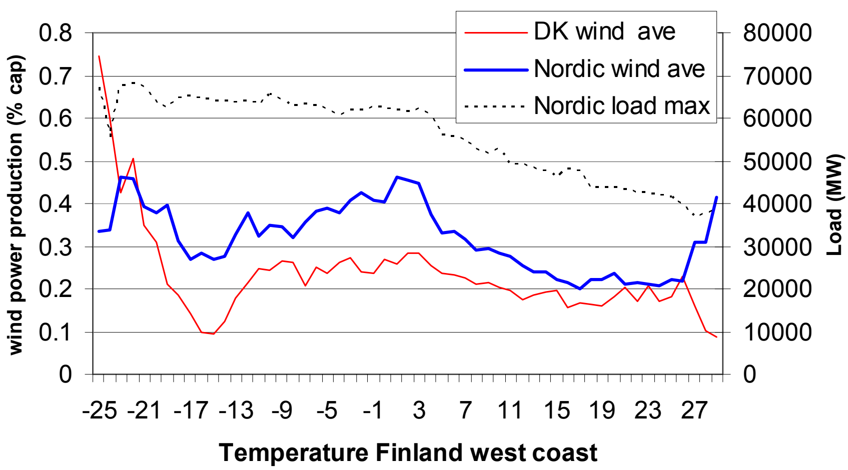


Figure 19. Wind power production and load in Nordic countries as a function of temperatures in Finland (2000–2001).

7.2 Capacity credit for wind power

Dimensioning the power system for system adequacy usually involves estimation of the Loss-of-load-probability LOLP index. As wind power production from one area can be zero during wintertime, it is often assumed that wind power does not contribute to the adequacy of the power production system and the capacity credit of wind power is neglected. Nevertheless, variable sources can save thermal capacity. Since no generating plant is completely reliable, there is always a finite risk of not having enough capacity available. Variable sources may be available at the critical moment when demand is high and other units fail. Fuel source diversity can also reduce risk.

Several studies show that at low system penetration the capacity value of wind power is close to that of a completely reliable plant generating the same average power at times when the system could be at risk (Giebel, 2001). As the penetration increases, wind power becomes progressively less valuable for saving thermal capacity (ILEX, 2003). The dispersion of wind power and a positive correlation between wind power and demand increase the value of wind power to the system. For very high penetration levels (more than 50 % of gross demand), the capacity credit tends towards a constant value, i.e. there is no increase in the capacity credit when increasing wind power capacity (Giebel, 2001). For hydro dominated systems, where the system is energy restricted instead of capacity restricted, wind power can have a significant energy delivery value. As wind energy correlates only weakly with hydro power production, wind energy added to the system can have a considerably higher energy delivery value than adding more hydro (Söder, 1999).

It has been shown that the capacity factor of wind power (i.e., production as % of installed capacity) during the peak load hours give a good indication of the capacity credit (Milligan & Parsons, 1997). Wind power production during the 10, 50 and 100 highest peak load hours, using data from this study, is shown in Table 2 for the different years and countries. Wind power production during the 10 highest peak load hours each year ranges between 7–60 % of installed capacity.

Results from a previous Finnish study indicate that the capacity credit for wind power in Finland is initially 23 %, but decreases to 18 % of installed capacity at a 6 % penetration (Peltola & Petäjä, 1993). This is a conservative estimate, assuming that large scale wind power would have a 7 % probability of not producing during wintertime. Two Danish studies estimated the capacity credit for 5, 10 and 15 % wind power penetration levels giving a capacity credit of 23–30 %, 16–25 % and 11–20 % of installed wind power capacity, respectively (Giebel, 2001). In Norway, the probability of wind power production is similar during high loads to the average (Alm & Tallhaug, 1993). The 3–4 year data in Table 2 give as the average capacity factor during high load situations 24–25 % in Denmark, 18–20 % in Finland, 23–26 % in Sweden, 46–54 % in Norway and 28–32 % in the 4 countries as a whole. This corresponds quite well with the above estimates for capacity credits of wind power.

Table 2. Wind power production, as % of installed capacity, during highest peak load hours.

	The whole year Average (min–max)	During 10 peaks Average (min–max)	During 50 peaks Average (min–max)	During 100 peaks Average (min–max)
Denmark 2000	24 % (0–93 %)	24 % (1–70 %)	31 % (1–87 %)	31 % (0–87 %)
Denmark 2001	20 % (0–90 %)	37 % (0–74 %)	30 % (0–87 %)	28 % (0–87 %)
Denmark 2002	22 % (0–91 %)	11 % (3–23 %)	14 % (2–53 %)	17 % (1–89 %)
Finland 1999	22 % (0–86 %)	7 % (5–10 %)	7 % (3–37 %)	9 % (2–46 %)
Finland 2000	24 % (0–91 %)	36 % (4–72 %)	32 % (3–75 %)	29 % (3–75 %)
Finland 2001	22 % (0–86 %)	19 % (3–38 %)	19 % (3–38 %)	17 % (3–38 %)
Finland 2002	20 % (0–84 %)	17 % (7–32 %)	17 % (6–54 %)	18 % (2–70 %)
Sweden 1999	25 % (0–100%)	23 % (16–29 %)	20 % (2–63 %)	20 % (1–66 %)
Sweden 2000	24 % (0–95 %)	16 % (7–49 %)	16 % (1–55 %)	16 % (0–63 %)
Sweden 2001	23 % (0–95 %)	47 % (40–51 %)	33 % (3–55 %)	29 % (3–63 %)
Sweden 2002	24 % (0–91 %)	16 % (3–36 %)	24 % (2–80 %)	25 % (2–80 %)
Norway 1999	32 % (0–100%)	55 % (17–86 %)	51 % (0–100%)	53 % (0–100%)
Norway 2000	34 % (0–93 %)	36 % (9–74 %)	35 % (9–74 %)	35 % (9–79 %)
Norway 2001	31 % (0–93 %)	61 % (39–84 %)	54 % (26–84 %)	46 % (15–84 %)
Norway 2002	32 % (0–86 %)	63 % (46–84 %)	58 % (22–84 %)	51 % (13–84 %)
Nordic 2000	27 % (1–81 %)	16 % (4–40 %)	21 % (4–56 %)	24 % (4–66 %)
Nordic 2001	24 % (1–84 %)	48 % (43–50 %)	37 % (9–56 %)	30 % (7–56 %)
Nordic 2002	25 % (1–73 %)	33 % (16–54 %)	33 % (11–61 %)	30 % (10–69 %)

8. Electricity markets and wind power

There have been changes in power system operation due to liberalised electricity markets. For example, even if the physical system is operated according to similar principles, the markets influence how the operating reserves are used. In chapter 6, the main emphasis was on the technical operation aspects of power systems. In this chapter, wind power in the electricity market is discussed. First, the market operation is described from the wind power producer's point of view. Then the effect of large scale production on market prices is discussed.

Wind power production has been marginal in the electricity markets so far. The bulk of wind power capacity is in countries with feed-in tariffs, where the TSO takes over the responsibility of balancing. In Denmark, the TSOs are trading a part of the wind energy produced in order to ease the scheduling of the conventional power plants. As the feed-in tariffs are for a specified time only (eg. 10 years), there will be an increasing amount of wind power coming to the markets during the next 5 to 10 years.

8.1 Market operation of a wind power producer

(Publication H)

In the Nordic countries, all bulk electricity production must be through a balance responsible player. For a wind power producer there are three options available. One option is to become a balance responsible player. Secondly, one could trade wind power and have a contract with a balance responsible player for balancing any mismatches. Thirdly, one could sell all wind power to a balance responsible player. It would be easier for the balance responsible player if there was flexibility in the production or consumption portfolio, and if there were several wind power projects geographically spread around to reduce the forecast error.

Producers with wind power bidding on the electricity market need to forecast their wind power production. Through forecast, the wind power available can be estimated when making a bid, selling all possible production. Forecast errors will result in an imbalance with the bid, which will be penalised and lead to reduced net income for the producer.

The income from the wind power produced is determined by the spot market (Figure 4). The cost of imbalances will be deducted from this income. For part of the time, the imbalance due to wind power may be opposite to the overall system imbalance, and for those hours there will be no cost. Depending on whether a one-price or a two-price model for the balance settlement is used, the above mentioned hours will either result in extra income (one-price-model) or will be reimbursed according to the spot price (two-price-model). The producers can trade outside the spot market for up to one hour before the delivery hour to reduce any larger imbalances.

It could be advantageous for the wind power producer to make a contract with a larger balance responsible player who owns regulating capacity. This is because the amount of imbalance cost is based on the net imbalance of the balance responsible player. The balance responsible player can also change the production schedule up to the delivery hour to reduce any larger imbalances.

8.1.1 Spot market income to a wind power producer

(Publication F)

The historical electricity spot market price level during wet and average hydro years[9] has not been enough to initiate investments in wind power without subsidies.

The price paid for wind power in the spot market will depend on how much wind energy is available in times of high price hours. The simulations for the Nordic market (EMPS model) over 30 years give about 2 % higher average value for wind power production than the average electricity spot price. With large scale wind production (12 % penetration) this price difference would

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[9] Average yearly spot price was 12–26 €/MWh in 2000–2002 and 37 €/MWh in 2003 (Nordpool, 2004).

reduce to about 1 %. In Denmark, with higher wind power penetration than in the other Nordic countries, wind power production would be priced 1–2 % lower than the average spot price.

The income for a wind power producer at spot market prices was calculated for the hourly wind power data collected for this study, assuming perfect prediction for wind power and geographically dispersed production. For Finland and Sweden in 2001 and 2002, the average income for wind power would have been 98–102 % of the average area spot price. In West Denmark with realised wind power production and system price the average income would have been 99–103 % of the average spot price. For the area price of West Denmark, the average income relative to average spot price decreased from 96 % to 86 % from 2001 to 2003 due to a larger share of wind power in the power system.

8.1.2 Regulation market cost for a wind power producer

(Publication C)

In publication C, a case study based on one year of wind power and market price data from Denmark was made to quantify the benefits of operating on a shorter forecast horizon. This study assumed that wind power producers of a larger area (West Denmark) formed a balance responsible player and had to take responsibility for all imbalances due to prediction errors. In year 2001 with 3.35 TWh of wind power or 16 % of the total electricity consumption:

- The prediction error for the year totals 39 % of the wind energy produced for the Nordpool 12–36 h market. With the two-price regulating power market, 31 % of the production incurred a regulating cost. For a 6–12 h market, 30 % of the total yearly energy would have been predicted wrongly, and 21 % of the production would have to be balanced at the regulation market. For a constantly operating hourly market, 18 % of the energy would be mispredicted and 10 % of the production would have to be balanced at the regulation market.

- The regulation cost for the 12–36 hour market would be 2.3 €/MWh when allocated for the wind power produced during 2001. The regulation cost would be reduced by 30 % and the net income increased by 4 % for a 6–12 hour market, compared with the 12–36 hour market. An hourly operation would reduce the regulation costs by nearly 70 % and increase the net income by 8 %.

- Trading at the after sales market Elbas, where the trade closes one hour before delivery, enables the wind power producer to trade the over- or under-predicted amount when the production is more accurately known. From 2001 data, the net income could increase by 7 % if trading at Elbas compared to trading at the Nordpool 12–36 h market only.

The results are not based on a state-of-the-art version of the prediction model, so the prediction errors of wind power are somewhat overestimated. It is assumed that the price level of the after sales market Elbas would stay near the day-ahead spot market prices most of the time. This means that wind power is not influencing the after sales market price more than the lowest-price-for-selling and highest-price-for-buying assumed here. On the other hand, acting at flexible markets could also bring about extra trading costs.

For a producer selling wind power production on the electricity market, there is a clear benefit in trading as close to the delivery hour as possible, since this reduces the prediction error and thus the extra cost from regulating. Also, a larger geographical area improves the forecasts.

The electricity market design will have a crucial effect on the balancing costs for wind power producers. The Dutch system of rewarding overproduction with 16 €/MWh and penalising undelivered power with 120 €/MWh would result in a drop in the net income of a wind power producer by over 50 %, if 25 % of the production were wrongly predicted (Hutting & Clejne, 1999). In a Danish study (Nielsen et al., 1999), the mispredictions of wind power production would impose a 1.3–2.7 €/MWh extra cost from settling the deviations at the balancing market. This is in line with the cost calculated here for year 2001 (2.3 €/MWh). These studies estimate the cost by relying on predictions that try to minimise the forecast error in energy. Market design can also change the bidding strategy from simply minimising the error in energy (Bathurst et al., 2002; Nielsen & Ravn, 2003).

Only the net imbalance in a power system needs to be balanced. In a large system this results in considerable benefit when imbalances from individual production units and consumption counteract one another. This could also be reflected by the balance settlement. The two-price model only penalises those having their imbalance on the same side as the system (net) imbalance. However, it does not recognise that only part of this imbalance, i.e. the net imbalance, needs to be corrected. In the one-price model, the ones having their imbalance in the opposite direction to the system will gain, as they are paid a price higher than the spot price. As the imbalance for wind power is about the same in both directions this results in almost no extra regulation costs for wind power in Norway (Gustafsson, 2002). In California, the imbalance for wind power is calculated as the average over a month, which also results in almost zero imbalance costs for wind power (Caldwell, 2002). In Denmark and Germany, allocating the balancing costs has been a part of the policy for increasing renewable power production, so any increase in imbalance costs is distributed evenly to all consumers.

The rules for balance services are based on producers that can influence their production amounts for most of the time. Market mechanism should not be a barrier for renewable production forms and mechanisms for intermittent sources such as wind power should be considered.

8.2 The impact of large amounts of wind power on spot market

(Publication F)

Due to its negligible variable costs, wind energy would always be taken up by the electricity market. This means that the supply curve will be shifted to the right with the amount of wind power bid to the market at that hour. The market cross will be formed either to the same price as without wind (when the amount of wind power is less than the amount of the production form on the margin) or a price lower to that without wind (Figure 4).

The results from the EMPS simulations for the Nordic electricity market give an average spot price of about 23 €/MWh for the year 2000 system in an average inflow situation. The average spot price rises to 35 €/MWh for the 2010 scenario, due to a CO_2 tax and reduced power surplus (more consumption than production capacity added). According to the simulations of these two different cases, adding a significant amount of wind energy to the Nordic system would decrease the average spot price by 2 €/MWh for each 10 TWh/a wind energy added. A decrease in spot market price is connected with adding wind power in the market as an extra production. Results of simulations when thermal capacity was decreased while adding wind, show only a moderate price decrease (about 2 €/MWh for each 40 TWh/a added wind production).

In West Denmark, with more than 15 % of gross demand from wind power, the area price was reduced to 0 during some hours in 2002 and 2003. This was due to too much production in the area, resulting partly from the local prioritised CHP production as well. The wind power production during those hours has been above average.

The implications of the lowering of spot market price are twofold. The consumers will gain from a price reduction, and when wind power is replacing fossil thermal production, the power system will be operating with less fuel consumption and emissions. For the producers of fossil fuel operated power plants this can be a crucial drop in income. If the capacity is removed even if it would be needed in extreme dry years, it could affect adequacy of supply. Wind power should replace fossil fuels, to make the CO_2 and other emission savings required. However, the way this is done, in practice and from a power system point of view maintaining the reliability can become an issue. Overcapacity in the Nordic countries when the electricity markets were started resulted in some of the capacity being mothballed, and it was taken back to operation during the dry period 2002–2003. This could also be the way the system security is maintained with large amounts of wind power if the time scale of dry and low wind periods allow for it.

8.3 The impact of wind power on the regulating power market

Regulating power is nearly always more expensive than bulk power on the electricity market. This is because it is used for short intervals only, and has to be kept on stand-by. Paying more for regulation power is also one incentive for the market players to maintain their power balance.

Since 2003, there has been a common regulating power market in the Nordic system. The decentralised balancing by the balance responsible players means that they will pay the costs of balancing through balance service, and move the costs associated forward to either the wind power producer or the consumers. Here the balancing means the deviations from the schedules submitted to TSOs before the operating hour[10]. There is the possibility of trading larger deviations in the Elbas market, closing 1 hour before. Self regulation is discouraged, however, as it is more cost effective for both the system and the individual players to bid all regulating power to a joint pool for the TSO to use the cheapest options first.

In California, a study of the existing wind power showed that even doubling the wind power in the area will not influence the regulating power market (less than 5 % penetration level) (Kirby et al., 2003). Large amounts of wind power will influence the regulating power market. In West Denmark, wind power penetration is large enough to influence the market price in the area. However, the common regulating power market in Nordel is not influenced by the Danish wind power as the wind power produced is less than 2 % of the gross demand of Nordel.

The historical electricity market prices are not valid with a high penetration level of wind power. On a 10–20 years time horizon, which may be relevant to a potential investor, it is difficult to predict the cost of balancing as well as the market value of wind power.

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[10] Sweden and Denmark: separately for production and consumption schedules.

9. Conclusions

The integration of large amounts of wind power is a challenge to power systems. In this work, the impact of large-scale wind power on the operation of the Nordic power system, on the electricity market operation and on market prices was studied.

The variability of wind power is reduced when considering a large interconnected system with geographically dispersed wind power production. In the Nordic countries, the aggregated wind power production will stay within 1–90 % of the installed wind power capacity, and production levels of above 75 % or below 5 % of the installed wind power capacity are rare. The hourly changes of the production are most of the time within ±10 % of installed capacity in one country and inside ±5 % of capacity in the whole Nordic area.

The increased reserve requirement for the power system is determined by combining the wind power variations with varying electricity consumption. Combined with the varying load, wind power will not impose major extra variations on the system until a substantial penetration is reached.

The increased reserve requirement is seen on a 15 minutes – 1 hour time scale. In the Nordic countries, wind power would increase the reserve requirements by 1 %, 2 and 4 % of wind power capacity at 5, 10 and 20 % wind power penetration of gross demand, respectively. The increased reserve cost is of the order of 1 €/MWh at a 10 % penetration and 2 €/MWh at 20 % penetration of wind power. This is halved if the conservative estimate for allocating investment costs for new reserve capacity to the wind power production is omitted and only increased use of reserves is taken into account. In addition, the prediction errors of wind power day-ahead may affect the system net imbalance and thus will reflect on the regulating power market, depending on how much the balance responsible players will correct the deviations before the operating hour.

The simulations of the Nordic power system show that wind power will mostly replace coal or gas condense power, partly in different countries to those with the installed wind power if the system is interconnected. The variability of wind power will first reflect in the increase in exchange between the countries before thermal power plants in the area of installed wind power will be affected. The reduction of CO_2 emissions in the Nordic countries is 700 gCO_2/kWh at low penetration of wind power, reducing to 620 gCO_2/kWh at higher than 10 % penetration. At penetration levels greater than 10 %, there would be increased losses in hydro power production of the order of 1 % of the produced wind energy. Based on the simulations confirmed by experience in West Denmark, discarded energy becomes relevant for the Nordic electricity system when wind power produces more than 20 % of the gross demand, or in some cases earlier if there are bottleneck situations in the interconnected Nordic network.

The analyses from 3 years of realised hourly data confirm the results from earlier studies that the capacity credit for wind power is close to average power produced. Wind power production in Finland and Denmark is lower than average at low ambient temperatures, but the Nordic wind power production does not show a similar trend.

The operation of wind power producers in the electricity market requires forecasting of the wind power production. The forecast errors are substantial when forecasting one day ahead: about 90 % of wind power production will be known 1 hour beforehand, 70 % 9 hours before, and only 50 % 36 hours before, respectively. The prediction errors will lead to balance deviations that will be charged according to regulating power market prices after the operating hour. The producer acting at the market can use after sales tools and bilateral trade to correct most of the error, as the production will be known more accurately some hours before delivery. This would increase the net income of a wind power producer by nearly 10 %, according to 2001 data. The market rules will have a crucial effect on the costs for intermittent production like wind power. The balancing costs for the wind power producers should reflect the real costs for the power system, from balancing the system net imbalance.

High penetrations of wind power will affect the market price – lower the spot market prices and raise the regulating power prices. High penetration of wind power will lower the Nordpool spot market prices by about 2 €/MWh for each 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand). This applies if the wind power production is added to the system without replacing any production capacity.

The results from this work clearly show the benefits of large interconnected systems in absorbing variable production like wind energy. The results of wind power variability and increased reserve requirements give new insight for the Nordic countries in particular and other power systems in general. Important future issues would be the effects of wind power on the regulating market prices and hourly energy system modelling, including wind power integration in a large interconnected system. When the penetration of wind power becomes greater, data on a minute or even second level would be beneficial to carry out transient studies on the variations of wind power and load.

Large-scale wind power utilisation still lies in the future for many countries. There are long-term trends that can influence the impact of wind power on the power system. A greater system interconnection is highly beneficial: wind power spread all over Europe would be a more reliable source. The use of electricity for vehicles may open up new possibilities for variable and intermittent power production. Producing fuel for vehicles that are only used for about 1000 hours per year will ease the flexibility needs in power systems.

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Power System Requirements for Wind Power

Hannele Holttinen and Ritva Hirvonen

8.1 Introduction

The power system requirements for wind power mainly depend on the power system configuration, the installed wind power capacity, and how the wind power production varies. Wind resources vary on every time scale: seconds, minutes, hours, days, months and years. On all these time scales, the varying wind resources affect the power system. An analysis of this impact will be based on the geographical area that is of interest. The relevant wind power production to analyse is that of larger areas, like synchronously operated power systems, comprising several countries or states.

The integration of wind power into regional power systems is mainly studied on a theoretical level, as wind power penetration is still rather limited. Even though the average annual wind power penetration in some island systems (e.g. Crete in Greece)[1] or countries (e.g. Denmark)[2] is already high, on average wind power generation represents only 1–2 % of the total power generation in the Scandinavian power system (Nordel) or the Central European system (UCTE). And the penetration levels in the USA (NERC regions) are even lower. Most examples in this chapter come from Central and Northern Europe, as there is already some experience with large-scale integration of wind power, and there are far-reaching targets for wind power. In Central Europe, power production is mostly based on thermal production, whereas in the Nordic countries thermal production is mixed with a large share of hydro power.

We will refer to the energy penetration when we use the term wind power penetration in the system. The energy penetration is the energy produced by wind power (annually) as a percentage of the gross electricity consumption. Low penetration means that less than 5 % of gross demand is covered by wind power production, high penetration is more than 10 %. First, this chapter will describe the power system and large-scale wind power production. We will then look at the effects of wind power production on power system operation as well as present results from studies in order to quantify these effects.

[1] See also chapter 14.
[2] See also chapter 3, 10 and 11.

8.2 Operation of the Power System

Electric power systems include power plants, consumers of electric energy and transmission and distribution networks connecting the production and consumption sites. This interconnected system experiences a continuous change in demand and the challenge is to maintain at all times a balance between production and consumption of electric energy. In addition, faults and disturbances should be cleared with the minimum effect possible on the delivery of electric energy.

Power systems comprise a wide variety of generating plant types, which have different capital and operating costs. When operating a power system, the total amount of electricity that is provided has to correspond, at each instant, to a varying load from the electricity consumers. To achieve this in a cost-effective way, the power plants are usually scheduled according to marginal operation costs, also known as merit order. Units with low marginal operation costs will operate almost all the time (base load demand), and the power plants with higher marginal operation costs will be scheduled for additional operation during times with higher demand. Wind power plants as well as other variable sources, like solar and tidal, have very low operating costs. They are usually assumed to be 0, therefore these power plants are at the top of the merit order. That means that their power is used whenever it is available. The electricity markets operate in a similar way, at least in theory. The price the producers bid to the market is slightly higher than their marginal cost, because it is cost-effective for the producers to operate as long as they get a price higher than their marginal costs. Once the market is cleared, the power plants that operate at the lowest bids come first.

If the electricity system fails the consequences are far-reaching and costly. Therefore, power system reliability has to be kept at a very high level. Security of supply has to be maintained both short-term and long-term. This means maintaining both flexibility and reserves that are necessary to keep the system operating under a range of conditions, also in peak load situations. These conditions include power plant outages as well as predictable or uncertain variations in demand and in primary generation resources, including wind.

The power system has to operate properly also in liberalised electricity markets. Usually, an Independent System Operator (ISO) is the system responsible grid company that takes care of the whole system operation, using active and reactive power reserves to maintain system reliability, voltage and frequency.

Reliability consists of system security and adequacy. The system security defines the ability of the system to withstand disturbances. The system adequacy describes the amount of production and transmission capacity in varying load situations.

8.2.1 System reliability

The planning of the power system is usually carried out according to mutually agreed principles. These principles include that the system has to withstand any single fault (e.g. the disconnection of a power plant, transmission line, substation busbar or power transformer) without major interruptions of the power delivery. The consequences of faults for the power system depend on the power transmission (i.e. the production and consumption of electric energy at a given moment), on the topology of the system and on the type of the fault. The most severe fault that a power system can withstand and that will not lead to inadmissible consequences is called dimensioning fault. The dimensioning fault varies according to the operational state of the system. Usually, it is the disconnection of the largest production unit or the busbar fault at a substation residing along an important transmission route.

Limits for power transfers are defined in predefined production and loading situations using power system analysis software, where the equipment (lines, substations, power plants and loads) is modelled together with connections and levels of production and load. In the simulations, the dimensioning fault(s) may not lead to situations, where synchronous operation is lost, or there may be voltage collapses, load shedding, large deviations in voltage/frequency, overloads or un-damped oscillations. The normal operational state of the power system is a power transfer state, where the system can withstand a dimensioning fault without the resulting disturbance spreading further than allowed. Within a normal operation area that consists of normal power transfer states, the faulty equipment can be disconnected in case of a fault. Disturbances are not allowed to spread to a larger area or cause a blackout of the system.

The system responsible ISO provides disturbance management that prevents faults from spreading and restores the system to normal operational state as soon as possible after the fault. The security of the power system is maintained by planning and operating the system in a way that minimises disturbances caused by faults. In order to manage disturbances, the system responsible grid operator keeps power transfers within the allowed limits and secures that the system has enough reserves in power plants and in the transmission grid.

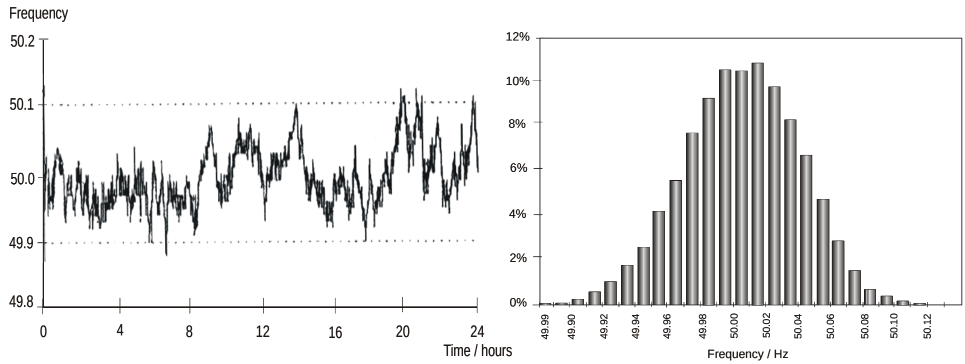
System adequacy is associated with static conditions of the system. It refers to the existence of sufficient electric energy production within the system to meet the load demand or constraints within the transmission and distribution system. The adequacy of the system is usually studied either by a simple generation–load model or by an extended bulk transmission system model consisting of generation, transmission, distribution and load. In a simple generation–load model, the total system production is examined to define its adequacy to meet the total system load. The estimation of the required production needs includes the system load demand and the maintenance needs of production units. The criteria that are used for the adequacy evaluation include the loss of load expectation (LOLE), the loss of load probability (LOLP) and the loss of energy expectation (LOEE), for instance.

The LOLP approach combines the applicable system capacity outage probability with the system load characteristics in order to arrive at the expected probability of loss of load. LOLE defines the number of days or hours per year with a probability of loss of load. LOEE defines the same values for energy (Billinton and Allan, 1988).

8.2.2 Frequency control

The power system that is operated synchronously has the same frequency. The frequency of a power system can be considered a measure of the balance or imbalance between production and consumption in the power system. With nominal frequency (e.g. in Europe 50 Hz, in the US 60 Hz), production and consumption, including losses in transmission and distribution, are in balance. If the frequency is below 50 Hz, the consumption of electric energy is higher than the production. If the frequency is above 50 Hz, the consumption of electric energy is lower than the production. The better the balance between production and consumption, the less the frequency deviates from its nominal value. In the Nordic Power System, for instance, the frequency is allowed to vary between 49.9 Hz and 50.1 Hz. Figure 8.1a shows an example of frequency variations during one day and figure 8.1b presents frequency variations during one week.

The primary frequency control in power plants is used to keep the frequency of the system within the allowed limits. The primary control is activated automatically if the frequency fluctuates. It is supposed to be fully activated when the maximum allowable frequency deviation (e.g. in Nordic Power System ± 0.1 Hz) is reached. Figure 8.2 shows an example of the actual load in the system during 3 hours compared to the hourly load forecast, including forecast errors and short-term load deviations in the system.



a) b)

Figure 8.1 Examples of: a) frequency variations in the system during one day; b) frequency distribution in the system during one week (Source: Hirvonen, 2000).

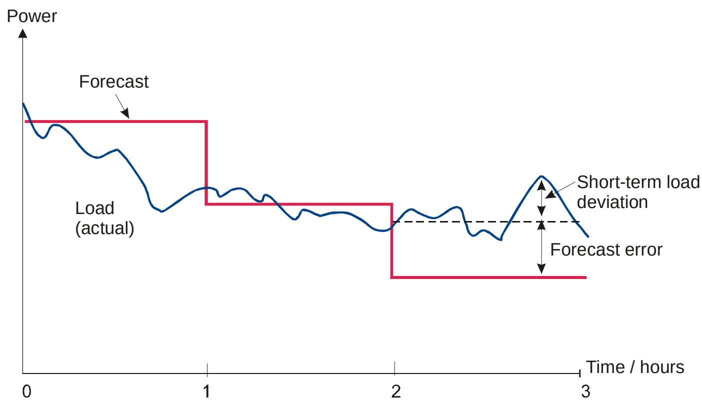


Figure 8.2 Example of actual load in the system during 3 hours compared to forecasted load. (Source: Holttinen, 2003)

If there is a sudden disturbance in balance between production and consumption in the power system, such as the loss of a power plant or a large load, primary reserves (also called disturbance reserve or instantaneous reserve) are used to deal with this problem. The primary reserve consists of active and reactive power supplied to the system. Figure 8.3 shows the activation of reserves and frequency of the system as a function of time, for a situation where a large power plant is disconnected from the power system. Their activation time divides the reserves into primary reserve, secondary reserve (also called fast reserve) and long-term reserve (also called slow reserve or tertiary reserve), as shown in figure 8.3.

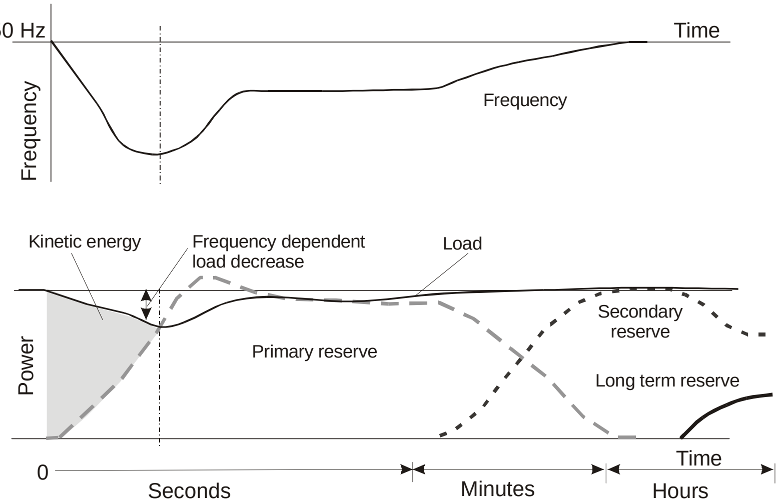


Figure 8.3 Activation of power reserves and frequency of power system as a function of time, for a situation where a large power plant is disconnected from the power system. (Source: Hirvonen, 2000).

The primary reserve is production capacity that is automatically activated within 30 seconds from a sudden change in frequency. It consists of active and reactive power in power plants, on the one hand, and loads that can be shed in the industry, on the other hand. Usually, the amount of reserve in a system is defined according to the largest power plant of the system, which can be lost in a single fault.

The secondary reserve is active or reactive power capacity activated in 10 to 15 minutes after the frequency has deviated from the nominal frequency. It replaces the primary reserve and it will be in operation until long-term reserves replace it, as shown in figure 8.3. The secondary reserve consists mostly of rapidly starting gas turbine power plants, hydro (pump) storage plants and load shedding. Every country in an interconnected power system should have a secondary reserve. It corresponds to the amount of disconnected power during the dimensioning fault (usually loss of largest power unit) in the country involved. In order to provide sufficient secondary power reserve, system operators may take load-forecast errors into account. In this case, the total amount of the secondary reserve may reach a value corresponding to about 1.5 times the largest power unit.

8.2.3 Voltage management

The voltage level in the transmission system is kept at a technical and economical optimum by adjusting the reactive power supplied or consumed. Power plants and special equipment, e.g. capacitors and reactors, control the reactive power. The voltage ratio of different voltage levels can be adjusted by tap-changers in power transformers. This requires a reactive power flow between different voltage levels.

In order to manage the voltage level during disturbances, reactive reserves in power plants are allocated to the system. These reserves are mainly used as primary reserves in order to guarantee that the voltage level of the power system remains stable during disturbances.

The voltage level management has the aim to prevent under- and over-voltages in the power system and to minimise grid losses. Voltage level management also guarantees that customer connection points have the voltages that were agreed by contracts.

8.3 Wind Power Production and the Power System

Wind energy is characterised by large variations in the production. If we look at the power system, we are interested in the wind power production of larger areas. Large geographical spreading of wind power will reduce variability, increase predictability and there will be less instances of near zero or peak output.

For power systems, the relevant information on wind power production is the probability distribution, the range and seasonal or diurnal patterns of the production, as well as the magnitude and the frequency of the variations (ramp rates).

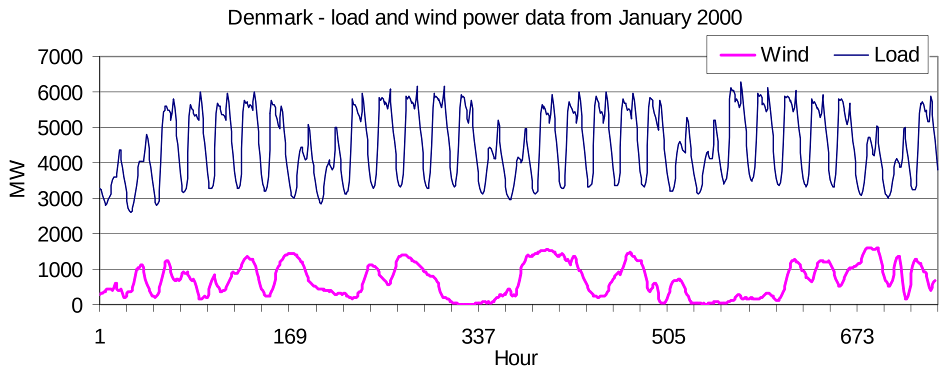


Figure 8.4 Example of large-scale wind power production: Denmark (both Zeeland and Jutland) in January 2000. Average wind power production in January was 687 MW and in 2000 all year 485 MW (~24 % of the installed capacity). (Source: Holttinen, 2003)

8.3.1 Production patterns of wind power

Wind power production is highly dependent on the wind resources at the site. Therefore the average production, the distribution of the production, as well as seasonal and diurnal variations can look very different at different sites and areas of the world. For most sites on land, the average power as the percentage of the nominal capacity (capacity factor c_p), is between 20–40 %. This can be expressed as full load hours of 1,800–3,500 h/a. Full load hours are the annual production divided by the nominal capacity. Offshore wind power production, or some extremely good sites on land, can reach up to 4,000–5,000 full load hours (c_p 45–60 %).

We can compare that to other forms of power generation. Combined heat and power production (CHP) has full load hours in the range of between 4,000–5,000 h/a, nuclear power 7,000–8,000 h/a, and coal fired power plants 5,000–6,000 h/a. However, full load hours are only used to compare different power plants. They do not tell us how many hours the power plant is actually in operation. Wind turbines, which operate most of the time at less than half of the nominal capacity, will typically produce power during 6,000–8,000 h/a (70–90% of the time).

The geographical spreading of the production evens out the variations of the total production from an area. There will be substantially less calm periods, as the wind will blow almost always somewhere in the area that the power system covers. On the other hand, maximum production levels will not reach the installed nominal capacity, as the wind will not have the same strength at all sites simultaneously. And out of hundreds or thousands of wind turbines not all will be technically available in each and every moment.

The duration curve of dispersed wind power production in figure 8.5 illustrates that: the production from one wind turbine is zero for 10–20 % of the time, and at nominal capacity 1–5 % of the time, whereas the production from large-scale wind power production is in this example rarely below 5 % or above 75 % of capacity.

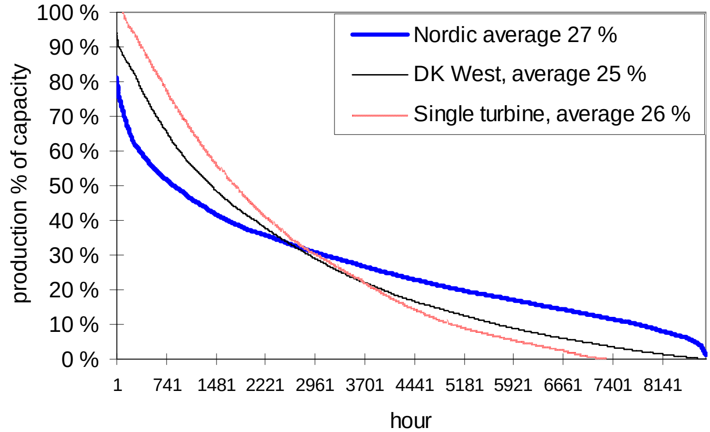


Figure 8.5 Increased resources and geographical spreading lead to a flattened duration curve of wind power production. Example of year 2000 hourly data, where wind power production from turbines throughout the four Nordic countries, Denmark, Finland, Norway and Sweden, is compared with one of the wind farms and one of the areas (Denmark, West). (Source: Holttinen, 2003)

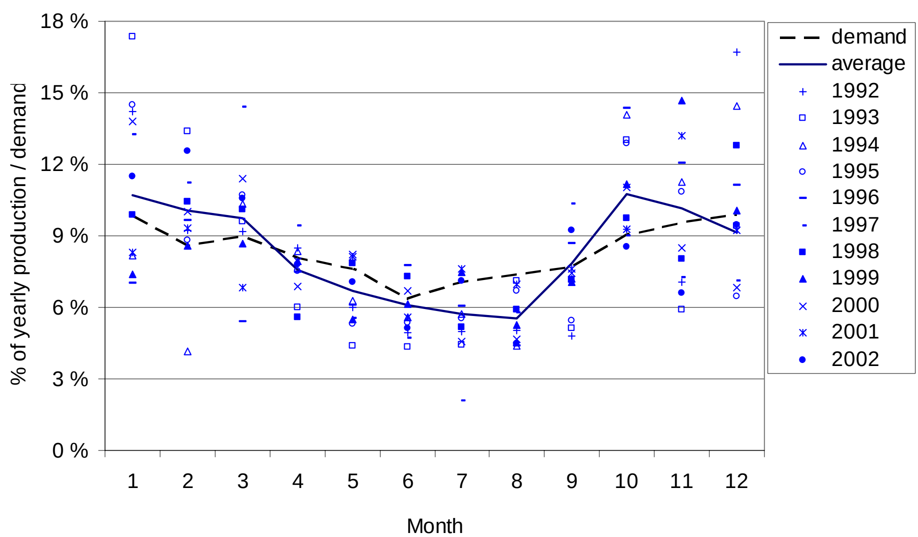


Figure 8.6 Seasonal variations of wind power production. Example from Finland for the years 1992–2002. Average monthly production in 1992–2002 is shown (solid line) together with the electric consumption in 2002 (dotted line). (Source: Holttinen, 2003)

Even for large-scale, geographically dispersed wind power production, the production range will still be large compared with other production forms. The maximum production will be three or even four times the average production, depending on the area (Holttinen, 2003, Giebel 2000).

The available wind resources will vary from year to year. Wind power production during one year lies at between ± 15 % of the average long-term yearly production (Ensslin et al, 2000; Giebel, 2001). However, the year-to-year variation in the production from hydro power can be even larger.

There is often a distinct yearly (seasonal) and daily (diurnal) pattern in wind power production. In Central and Northern Europe, there is more production in winter than in summer (Fig. 8.6).

Wind is driven by weather fronts. It may also follow a daily pattern caused by the sun. Depending on what is prevalent in the region, there is either a strong or hardly any diurnal pattern in the production. There are many sites where the wind often starts to blow in the morning and calms down in the evening (Hurley and Watson, 2002; Ensslin et al, 2000). In Northern Europe, this is most pronounced during the summer (see Figure 8.7). Diurnal variation can also be due to local phenomena. An example would be the mountain ranges in California with morning and evening peaks, when wind blows from the desert to the sea and in the opposite direction, respectively.

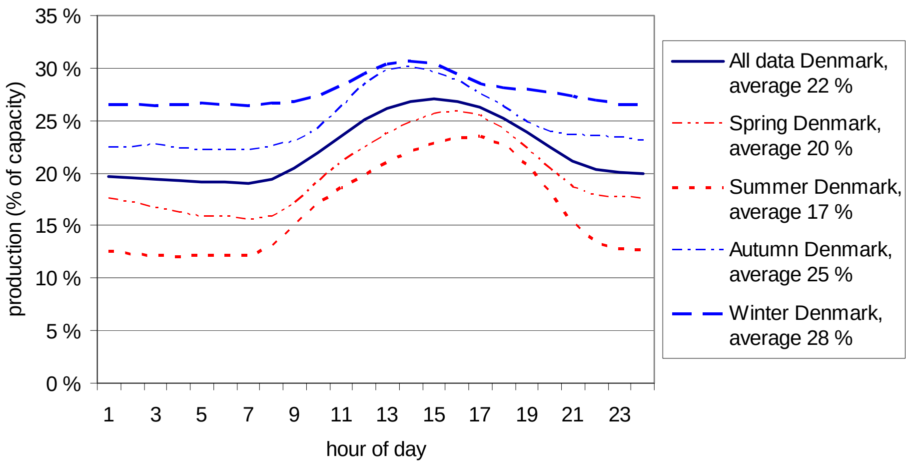


Figure 8.7 Diurnal variations of wind power production are larger during the summer, example from Denmark.

8.3.2 Variations of production and smoothing effect

The wind speed varies on all time scales, and this has different effects on the power system. Wind gusts cause variations in the range of seconds or minutes. The changing weather patterns can be seen from the hourly time series of wind power production. This time scale also illustrates the diurnal cycle. Seasonal cycles and annual variations, on the other hand, are important for long-term adequacy studies. For the system planning, it is important to look at extreme variations of large-scale wind power production, together with the probability of such variations.

The larger the area, the longer the periods of time over which the smoothing effect extends. Figure 8.8 shows the decreasing correlation[3] of the variations for different time scales (Ernst, 1999). The correlation is here calculated for the differences between consecutive production values (ΔP). For the time series of production values, the correlation does not decrease as rapidly as shown here. Within one wind farm, gusts (seconds) will not effect all wind turbines at exactly the same moment. However, the hourly wind power production will follow approximately the same ups and downs. In a larger area covering several hundreds of square kilometres, the weather fronts causing high winds will not pass simultaneously over the entire regions. However, high and low wind months will coincide for the whole area.

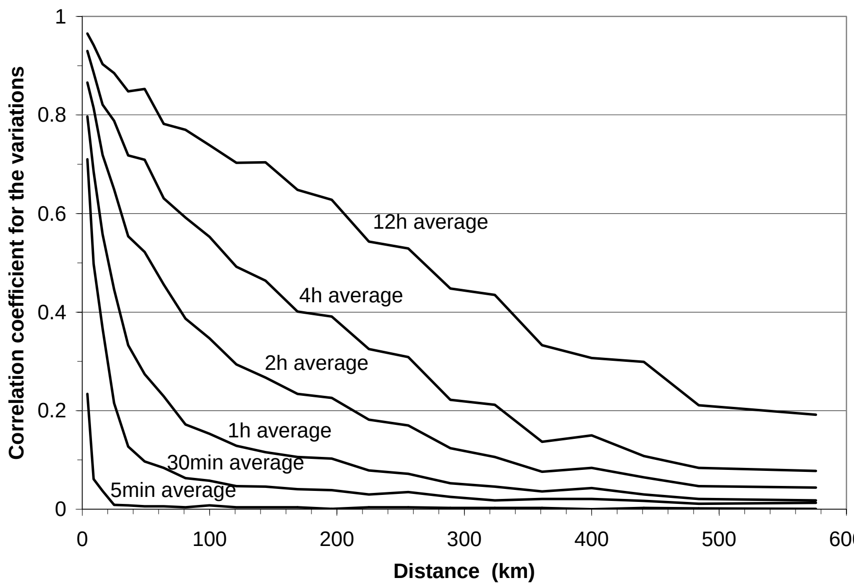


Figure 8.8 Variations will smooth out faster when the time scale is small. Correlation of variations for different time scales, example from Germany (Ernst, 1999).

How large is the smoothing effect? It becomes more noticeable if there is a larger number of turbines spread over a larger area. The smoothing effect of a specified area has an upper limit. There will be a saturation of the amount of variations, i.e. where an increase in the number of turbines will not decrease the (relative) variations by the total wind power production of the area. Beyond that point, the smoothing effect can be only increased when the area becomes larger. And there is a limit to that, too. The examples we use are from comparatively uniform areas. If wind power production is spread over areas with different weather patterns (coast/mountains/desert), the smoothing effect will probably be stronger.

[3] Cross-correlation r_{xy} is a measure of how well two time series follow each other: it is near the maximum value 1 if the ups and downs of the production occur simultaneously, near the minimum value –1 if there is a tendency of decreasing production at one site while increasing production at the other site, and it is close to zero if the two are uncorrelated, and the ups and downs of production at two sites do not follow each other.

$$r_{x,y} = \frac{\frac{1}{n}\sum_{i=1}^{n}(x_i - \mu_x)(y_i - \mu_y)}{\sigma_x \sigma_y}$$

, where μ denotes the average, σ the standard deviation and n the number of points in the time series.

The smoothing effect is illustrated by the statistical parameters of the production (P) and fluctuation (ΔP) time series, i.e. the maximum variations of production (extreme ramp rates), the probability distribution of the variations and the standard deviation (σ).

The second-to-second variations will be smoothed out already for one wind turbine. The inertia of the large rotating blades of a variable speed wind turbine smoothes out very fast gusts. Second-to-second variations will be absorbed in the varying speed of the rotor of a variable speed wind turbine. The extreme ramp rates that were recorded for a 103 MW wind farm are: 4…7 % of capacity in a second, 10…14 % of capacity in a minute and 50…60 % of capacity in an hour (Parsons et al, 2001). However, system operation is concerned with an area that is much larger than the area in this example. For a larger area with geographically dispersed wind farms, the second and minute variations will not be significant, and the hourly variations will be considerably less than 50–60 % of capacity.

The largest hourly variations are about ± 30 % of capacity when the area is in the order of 200x200 km^2 (such as West/East Denmark), about ± 20 % of capacity when the area is in the order of 400x400 km^2 (such as Germany; Denmark; Finland; Iowa, US) and about ± 10 % in larger areas covering several countries, e.g. the Nordic countries (ISET, 2002; Holttinen, 2003; Milligan & Factor, 2000). These are extreme values. Most of the time the hourly variations will be within ± 5 % of installed capacity (Fig. 8.9).

If the geographic dispersion of wind power increases, the standard deviation for hourly time series decreases, which means that the variability in the time series is reduced. The standard deviation of hourly time series decreases to 50–80 % of the single site value (Focken et al, 2001; Holttinen, 2003). The standard deviation of the time series of fluctuations ΔP will decrease even faster, from about 10 % of capacity for a single turbine to less than 3 % for an area like Denmark or Finland and to less than 2 % for the 4 Nordic countries (Milborrow, 2001; Holttinen, 2003).

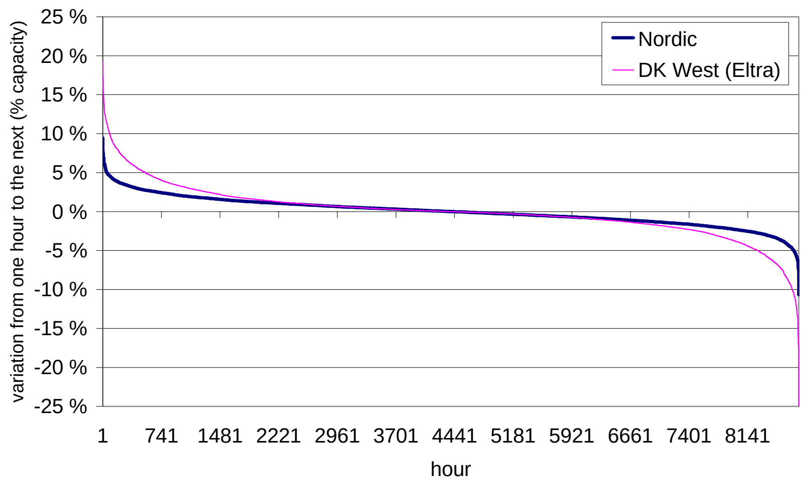


Figure 8.9. Variation of wind power production from one hour to the next. Duration curve of variations, as a percentage of installed capacity, for Denmark (Jutland) and for the theoretical Nordic wind power production assuming equal production in each of the four countries, year 2000. (Source: Holttinen, 2003)

According to (ISET, 2002), in Germany, maximum variation for 4 hours ahead is 50 % of capacity and for 12 hours ahead is 85 % of capacity. If we take larger areas, such as Northern Europe, there is a ± 30 % variation in production 12 hours ahead only about once a year (Giebel, 2000). For longer time scales (i.e. 4–12 h variations), prediction tools give valuable information on the foreseeable variations of wind power production.

Diurnal variations in output can help to indicate at what time of the day significant changes in output are most likely to occur. The probability of significant variations is also a function of the output level. Significant variations are most likely to occur when wind farms operate at between 25–75 % of capacity. This output level corresponds to the steep part of the power curve when changes in wind speed produce the largest changes in power output of the turbines (Poore & Randall, 2001).

There are also means to reduce the variations of the wind power production. Staggered starts and stops from full power as well as reduced (positive) ramp rates can reduce the most extreme fluctuations, in magnitude and frequency, over the short time scales. However, this is at the expense of production losses. Therefore, the frequent use of these options should be weighed against other measures (in other production units), regarding their cost effectiveness.

8.3.3 Predictability of wind power production

Wind power prediction plays an important part in the system integration of large-scale wind power. If the share of installed wind power is substantial, information regarding the on-line production and predictions of 1 to 24 h ahead are necessary. Day-ahead predictions are required in order to schedule conventional units. The starting up and shutting down of slow starting units has to be planned in an optimised way in order to keep the units running at the highest efficiency possible and to save fuel and thus operational costs of the power plants. In liberalised electricity markets, this is dealt with at the day-ahead spot market. Predictions of 1–2 h ahead help to keep up the optimal amount of regulating capacity at the system operators’ disposal.

Predictability is most important both at times of high wind power production and for a time horizon of up to 6 hours ahead, which gives enough time to react on varying production. An estimate of the uncertainty, especially the worst-case error, is important information.

Forecast tools for wind power production are still under development and they will be improving.[4] The predictions of the power production 8 hours ahead or more rely almost entirely on meteorological forecasts for local wind speeds. In northern European latitudes, for example, the variations of wind power production correspond to weather systems passing the area, causing high winds, which then calm down again. The wind speed forecasts of the Numerical Weather Prediction models contribute the largest error component. So far, an accuracy of ± 2–3 m/s (level error) and ± 3–4 h (phase error) has been sufficient for wind speed forecasts. However, the power system requires a more precise knowledge of the wind power production[5].

For larger areas, the prediction error decreases. For East and West Denmark, for example, including East Denmark adds 100 km, or 50 % more to West Denmark’s area, in the direction in which most weather systems pass. The errors of day-ahead predictions would cancel out each other to some extent for about a third of the time, when production is overpredicted in the West and underpredicted in the East, or vice versa (Holttinen, 2004).

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[4] See also Chapter 17.

[5] See also Chapters 10.

8.4 Effects of Wind Energy on the Power System

The impact of wind power on the power system depends on the size and inherent flexibility of the power system. It is also related to the penetration level of wind power in the power system.

When studying the impact of wind power on power systems, we refer to an area that is larger than only one wind farm. According to the impact that is analysed, we have to look at the power system area that is relevant. For voltage management, only areas near wind power plants should be taken into account. Even though there should be enough reactive power reserve in the system during disturbances, the reserve should mainly be managed locally. For intra-hour variations, frequency control for load following, we should look at the area of the synchronously operated system. DC links connecting synchronously operated areas can also be automised to be used for primary power control[6]. However, their power reserve capacity is usually only allocated as emergency power supply. For the day-ahead hourly production, a relevant area would be the electricity market. The Nordic power market, for instance, includes countries that are situated in different synchronous systems. Large interconnected areas lead to substantial benefits, unless there are bottlenecks in transmission[7].

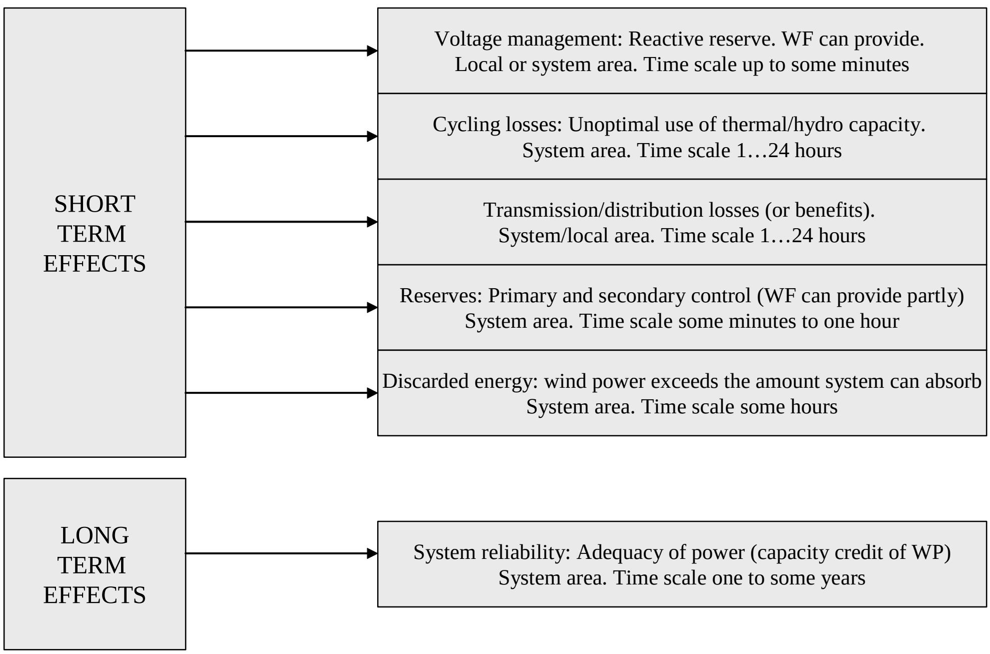

Figure 8.10 Power system impacts of wind power, causing integration costs. Some of the impacts can be beneficial for the system, and wind power can provide a value, not only costs (Source Holttinen, 2003).

If we analyse the incremental effects that a varying wind power production has on the power system, we have to study the power system as a whole. The power system serves all production units and loads. The system has only to balance the net imbalances.

Power system studies require representative wind power data. If the data from too few sites is up-scaled the power fluctuations will be up-scaled, too. If large-scale wind power production with steadier wind resources (e.g. offshore or large wind turbines with high

[6] See Chapter 10.
[7] See Chapter 20.

towers) is incorporated into the system, measurements from land or with too low masts will, in turn, over-estimate the variations. In addition, most studies will require several years of data.

Figure 8.10 includes a schematic representation of the impact that wind energy has on the system. These impacts can be categorised as follows:

- short-term: balancing the system on the operational time scale (minutes to hours)
- long-term: providing enough power during peak load situations.

These issues will be discussed in more detail in the following sections. For long-term trends affecting the integration of wind power into future power systems, see section 8.4.4.

8.4.1 Short-term effects on reserves

The additional requirements and costs of balancing the system on the operational time scale (from several minutes to several hours) are primarily due to the fluctuations in power output generated from wind. A part of the fluctuations is predictable for 2 h to 40 h ahead. The variable production pattern of wind power changes the scheduling of the other production plants and the use of the transmission capacity between regions. This will cause losses or benefits to the system due to the incorporation of wind power. Part of the fluctuations, however, is not predicted or wrongly predicted. This corresponds to the amount that reserves have to take care of.

The impact on reserves has to be studied on the basis of a control area. It is not necessary to compensate every change in the output of an individual wind farm by a change in another generating unit. The overall system reliability should remain the same, before and after the incorporation of wind power. The data used for wind power fluctuations is critical to the analysis. It is important not to up-scale the fluctuations when wind power production in the system is up-scaled. Any wind power production time series that is simulated or based on meteorological data should therefore follow the statistical characteristics that were presented in the section 8.3 (Milborrow, 2001; Holttinen, 2003).

The system needs power reserves for disturbances and for load following. Disturbance reserves are usually dimensioned according to the largest unit outage. As wind power consists of small units, there is no need to increase the amount of disturbance reserve (even large offshore wind farms still tend to be smaller than large condense plants). Hourly and less than hourly variations of wind power affect the reserves that are used for frequency control (load following), if the penetration of wind power is large enough to increase the total variations in the system.

Prediction tools for wind power production play an important role in the integration. The system operator has to increase the amount of reserves in the system because, in addition to load swings, it has to be prepared to compensate unpredicted variations in the production. The accuracy of the wind forecasts can contribute to risk reduction. An accurate forecast allows the system operator to count on wind capacity, thus reducing costs without jeopardising system reliability.

The requirement of extra reserves is quantified by looking at the variations of wind power production, hourly and intra-hour, together with load variations and prediction errors. Extra reserve requirement of wind power, and the costs associated with it, can be estimated either by system models or by analytical methods using time series of wind power production together with system variables. Wind power production is not straightforward to model in the existing dispatch models, because of the uncertainty of forecast errors involved on several time scales, for instance (Dragoon and Milligan, 2003). Below, we will briefly describe analytical methods with statistical measures.

The effect of the variations can be statistically estimated using standard deviation. What the system sees is net load (load minus wind power production). If load and wind power production are uncorrelated, the net load variation is a simple root-mean-square combination of the load and wind power variation:

$$(\sigma_{total})^2 = (\sigma_{load})^2 + (\sigma_{wind})^2 \tag{8.1}$$

The larger the area in question and the larger the inherent load fluctuation in the system, the larger the amount of wind power that can be incorporated into the system without increasing variations. The reserve requirement can be expressed as three times the standard deviation (3σ cover 99 % of the variations of a Gaussian distribution). The incremental increase from combining load variations with wind variations is 3 times ($\sigma_{total} - \sigma_{load}$). More elaborate methods allocating extra reserve requirements for wind power can be used, especially with non-zero correlations and any number of individual loads and/or resources (Kirby & Hirst, 2000; Hudson et al, 2001).

On the time scale of seconds/minutes (primary control) the estimates for increased reserve requirements have resulted in a very small impact (Ernst, 1999; Smith et al, 2004). This is due to the smoothing effect of very short variations of wind power production; as they are not correlated they cancel out each another, when the area is large enough.

For the time scale of 15 min…1 hour (secondary control) it should be taken into account that load variations are more predictable than wind power variations. For this, data for load and wind predictions are needed. Instead of using time series of load and wind power variations, the time series of prediction errors one hour ahead are used and standard deviations are calculated from these. The estimates for reserve requirements due to wind power have resulted in an increasing impact if penetration increases. For a 10 % penetration level, the extra reserve requirement is in the order of 2…8 % of the installed wind power capacity (Milborrow, 2001; Milligan, 2003; Holttinen, 2003).

Both the allocation and the use of reserves cause extra costs. Regulation is a capacity service and does not involve net energy, as the average of regulation time series is zero. In most cases, the increase in reserve requirements at a low wind power penetration can be handled by the existing capacity. This means that only the increased use of dedicated reserves, or increased part-load plant requirement, will cause extra costs (energy part). After a threshold, also the capacity cost of reserves has to be calculated. This threshold depends on the design of each power system. Estimates of this threshold suggest for Europe a wind power (energy) penetration of between 5 and 10 % (Milborrow, 2001; Persaud et al, 2000; Holttinen, 2003).

Estimates regarding the increase in secondary load following reserves in the UK's and US thermal systems suggest 2–3 €/MWh for a penetration of 10 % and 3–4 €/MWh for higher penetration levels (Smith et al 2004; Dale et al, 2004; DTI, 2003)[8]. The figures may be exaggerated because the geographical smoothing effect is difficult to incorporate into wind power time series. In California, the incremental regulation costs for existing wind power capacity is estimated to 0.1 €/MWh, for wind energy penetration of about 2 % (Kirby et al, 2003).

Also the recently emerged electricity markets can be used to estimate the costs for hourly production and regulating power. An ideal market will result in the same cost effectiveness as the optimisation of the system in order to minimise costs. However, especially at an early stage of implementing a regulating market or due to market power, the market prices for regulation can differ from the real costs that the producers have.

[8] Currency exchange rate from the end of 2003 used: 1 € = 1.263 $; 1 € = 0.705 £

In a market-based study, Hirst (2002) estimated the increase in regulation (second/minute time scale) that would be necessary to maintain system reliability at the same level, before and after the implementation of wind power. The result was that the regulation cost for a large wind farm would be between 0.04 and 0.2 €/MWh. This result applies to systems where the cost of regulation is passed on to the individual generators, and not provided as a general service by the system operator.

In West Denmark, with a wind penetration of about 20 %, the cost for compensating forecast errors in day-ahead market at the regulating market amounted to almost 3 €/MWh [9].

In the electricity market, the costs for increased regulation requirements will be passed on to the consumers, and the production capacity providing for extra regulation will benefit from that. Regulation power nearly always costs more than the bulk power available on the market. The reason is that it is used during short intervals only, and that is has to be kept stand-by. Therefore, any power continuously produced by that capacity cannot be sold to the electricity spot market. The cost of reserves depends on what kind of production is used for regulation. Hydro power is the cheapest option and gas turbines are a more expensive one. The cost of extra reserves is important when the system needs an increasing amount of reserves, because of changes in the production or consumption, such as increased load. The costs of regulation may rise substantially and suddenly in a phase when the cheapest reserves have already been used and the more expensive new reserves have to be allocated.

The cost estimates for thermal systems include the price for new reserve capacity and assume a price for lower efficiency and part load operation. To fully integrate wind power into the system in an optimal way means using the characteristics and flexibility of all production units in a way that is optimal for the system. Also a wider range of options in order to increase flexibility can be used. Some examples for already existing technologies that could be used to absorb more variable energy sources are:

- Increased transmission between the areas or countries or synchronous systems.
- Demand-Side-Management (DSM) / Demand-Side-Bidding (DSB).
- Storage: thermal storage with CHP regulating, electrical storage can become cost-effective in the future, but is still expensive today.
- Making the electricity production of CHP units flexible by using alternatives for heat demand (heat pumps, electric heating, electric boilers).
- Short-term flexibility implemented in wind farms. When based on reducing the output of wind power, this means loss of production. The desired flexibility can be achieved more cost-efficiently by conventional generation, if it requires an extensive reduction of wind power output.

Even simple statistical independence makes different variable sources more valuable than just more of the same, such as wind power and solar energy. It may also be beneficial to combine wind power with energy limited plants where the maximum effect cannot be produced continuously because the availability of energy is limited. This is the case of hydro power and biomass. Power systems with large hydro power reservoirs have the option to use hydro power to smooth out the variability of wind power by shifting the time of energy delivery (Tande and Vogstad, 1999; Vogstad et al, 2000; Krau et al, 2002). This is possible also for short response times, within the operating constraints of flow and ramp rates of hydro power (Söder, 1999).

[9] See also chapter 10.

8.4.2 Other short-term effects

Other effects that wind power has at the operational level of the power system include its impact on losses in power systems (generation and transmission/distribution) and on the amount of fuel used and on emissions, e.g. CO_2. There is already technology which allows wind farms to benefit power system operation, e.g. by providing voltage management and reactive reserve (in the case of type D turbines that are connected to the network or in a limited way also in the case of type C turbines) as well as primary power regulation (Kristoffersson, 2002). This issue of reliability is not discussed in detail here.

Wind power can either decrease or increase the transmission and distribution losses, depending on where it is situated in relation to the load. However, large-scale wind power can result in an increased transmission between regions. That can lead to increased transmission losses or a larger number of bottlenecks in transmission[10]. For the UK, concentrating the wind power generation in the North would double the estimated extra transmission costs to 2 and 3 €/MWh at a penetration level of between 20 and 30 %. This would not be the case if production was more geographically dispersed (DTI, 2003). At more modest penetration levels, transmission costs would decrease.

Large amounts of intermittent wind power production can cause losses in conventional generation. The decreased efficiency of the system is caused by thermal or hydro plants operating below their optimum (starts, shutdowns, part load operation). The optimised unit commitment, i.e. planning the starts and shut-downs of slow-starting units, is complicated by the intermittent output from a wind resource. An accurate prediction of the wind power production will help to solve this problem. However, even with accurate predictions, the large variations in wind power output can result in conventional power plants operating in a less efficient way. The effect on existing thermal and/or hydro units can be estimated by simulating the system on an hourly basis. At low penetration levels, the impact of wind power is negligible or small (Grubb, 1991; Söder, 1994), although costs for large prediction errors in a thermal system have amounted to about 1 €/MWh (Smith et al, 2004)

If wind power production exceeds the amount that can be safely absorbed while still maintaining adequate reserves and dynamic control of the system, a part of the wind energy production may have to be curtailed. Energy is only discarded at substantial penetration levels. Whether such a measure is taken depends strongly on the operational strategy of the power system. The maximum production (installed capacity) of wind power is several times larger than the average power produced. This means that there are already some hours with nearly 100 % instant (power) penetration (wind power production equals demand during some hours), if about 20 % of yearly demand comes from wind power. There is experience from and studies on thermal systems that take in wind power production, but leave, even at high winds, the thermal plants running at partial load in order to provide regulation power. The results show that about 10 % (energy) penetration is the starting point where a curtailing of wind power may become necessary. When wind power production is about 20 % of yearly consumption, the amount of discarded energy will become substantial and about 10 % of the total wind power produced will be lost (Giebel, 2001;CER/OFREG NI, 2003). For a small thermal island system, e.g. on Crete, Greece, discarded energy can reach significant levels already at a penetration of 10 % (Papazoglou, 2002).

For other areas, integration problems may arise during windy periods, if production in the area exceeds demand and also transmission capacity to neighbouring systems. This can be especially pronounced during windy, cold periods when there is also a substantial share of local, prioritised combined heat and power (CHP) production, as is the case of

[10] See chapter 20

Denmark[11]. When initially in West Denmark wind energy was discarded, this happened at penetration levels of 20 % rather than 10 %. With energy system models it has been estimated, that by using the existing heat storage and boilers of CHP production units together with wind power, and assuming some flexible demand and electrical heating, a 50 % wind power penetration could be possible without discarding any energy (Lund & Münster, 2003).

Wind power is renewable energy, practically free from CO_2. CO_2 emissions from the manufacturing and construction are in the order of 10 gCO_2/kWh. If wind energy replaces generation that emits CO_2, CO_2 emissions from electricity production are reduced. The amount of CO_2 that will be abated depends on what production type and fuel is replaced at each hour of wind power generation. This will be the production form in use at each hour that has the highest marginal costs. Usually, this is the older coal fired plants, resulting in a CO_2 abatement of about 800–900 gCO_2/kWh, often cited as the CO_2 abatement of wind energy. This is also true for larger amounts of wind power production, for countries that generate their electricity mainly from coal. In other countries, though, there may be a different effect if large amounts of wind power are added to the system. There may not be a sufficient number of old coal plants whose capacity can be replaced by the wind power production throughout the year. During some hours of the year, wind power generation would replace other production forms, such as the production of gas fired plants (CO_2 emissions of gas are 400–600 gCO_2/kWh), or even CO_2 free production, e.g. hydro, biomass or nuclear power. Instant (regulated) hydro production can be postponed and will replace condensing power at a later instant. Simulations of the Nordic system, for example, which is a mixed system of thermal and hydro production, result in a CO_2 reduction of 700 gCO_2/kWh (Holttinen&Tuhkanen, 2004). This is the combined effect of wind power replacing other fuels.

8.4.3 Long-term effects on the adequacy of power capacity

The intermittent nature of wind energy poses challenges to utilities and system operators. These must be able to serve loads with a sufficiently low probability of failure. The economic, social and political costs of failing to provide adequate capacity to meet demand are so high that utilities have traditionally been reluctant to rely on intermittent resources for capacity.

Dimensioning the system for system adequacy usually involves estimations of the Loss-of-load-probability LOLP index. The risk at system level is the probability (LOLP) times the consequences of the event. For an electricity system, the consequences of a blackout are large, thus the risk is considered substantial even if the probability of the incident is small. The required reliability of the system is usually in the order of one larger blackout in 10–50 years.

What impact does wind power have on the adequacy of power production in the system – can wind power replace part of the (conventional) capacity in the system? For answering this question, it is critical we know wind power production during peak load situations. This also means that to assess the ability of wind power to replace conventional capacity, i.e. the capacity credits, it is important either to have representative data for several years (one year is not enough) or to make a variability assessment (Milligan, 2000; Giebel, 2001).

Some variable sources can be relied on to produce power at times of peak demand. Solar energy, for instance, follows air-conditioning loads and wind energy reflects heating demand. If a diurnal pattern in wind power production coincides with the load (e.g. wind

[11] See Chapter 10.

power production increases in the morning and decreases in the evening) this effect is beneficial. However, in most cases there is no correlation between load and the availability of this variable source. In Northern Europe, for example, even if the seasonal variations mean that more wind power is available in winter than in summer, there is not a strong correlation between the high loads in winter and high wind power production. In Denmark, the correlation is slightly positive (about 0.2), but there is usually less correlation during higher load winter months than in the summer months.

In Northern Europe, the load is strongly correlated to outside temperature. The correlation between wind power production and temperature has an effect on the adequacy of power production, when determining the capacity value of wind power (see figure 8.11). Looking at wind power production during the 10 highest peak load hours each year, it ranges between 7–60 % of capacity (years 1999–2001 in the Nordic countries, Holttinen, 2003).

Nevertheless, variable sources can save thermal capacity. Since no generating plant is completely reliable, there is always a finite risk of not having enough capacity available. Variable sources may be available at the critical moment when demand is high and many other units fail. Fuel source diversity can also reduce risk.

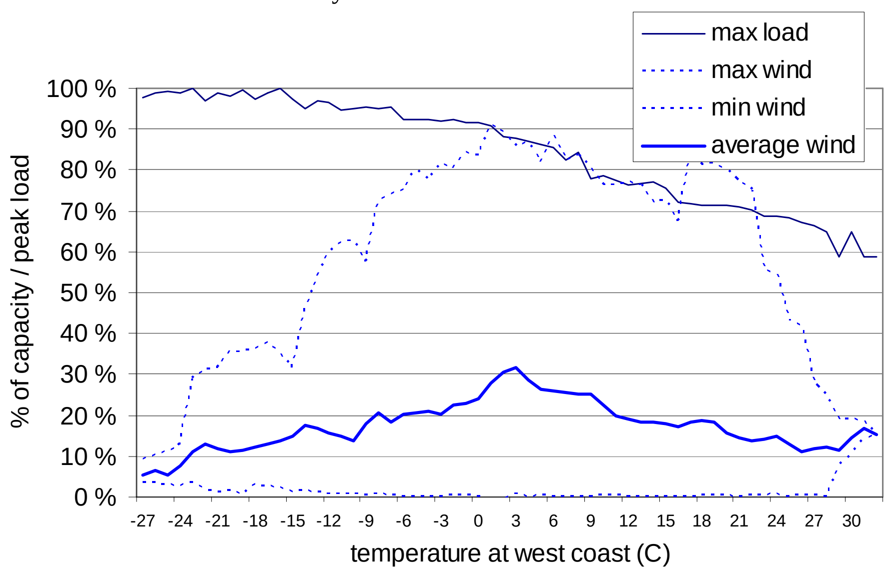

Figure 8.11 Correlation of temperature to wind power production and load in a cold climate, example of Finland, geographically dispersed wind power. There were 48 hours (0.1 % of time) below –23 °C and 549 hours (1.6 % of time) below –14°C during the years 1999–2002. (Source: Holttinen, 2003)

It has been shown in several studies that if the capacity of a variable source is small (low system penetration) the capacity value equals that of a completely reliable plant generating the same average power at times when the system could be at risk. As the penetration increases, variable sources become progressively less valuable for saving thermal capacity (DTI, 2003). The dispersion of wind power and a positive correlation between wind power and demand increase the value of wind power to the system. For very high penetration levels, the capacity credit tends towards a constant value, that is, there is no increase in the capacity credit when increasing wind power capacity. This will be determined by the LOLP without wind energy and the probability of zero wind power (Giebel, 2001).

If there is a substantial amount of wind power in the system (>5 % of peak load), an optimal system to accommodate wind power would contain more peaking and less base plants than a system without wind power. For hydro dominated systems, where the system is energy restricted instead of capacity restricted, wind power can have a significant energy delivery value. As wind energy correlates only weakly with hydro power production, wind energy added to the system can have a considerably higher energy delivery value than adding more hydro[12] (Söder, 1999).

8.4.4 Wind power in future power systems

Large-scale wind power still lies in the future for many countries. There are long-term trends that can influence the impact of wind power on the system. If there are large amounts of intermittent energy sources in the system, new capacity with lower investment costs (and higher fuel costs) will be favoured. The trend of increasing distributed generation from flexible gas turbines is beneficial for the integration of wind power, as is increasing load management. A greater system interconnection is highly beneficial as well: wind power spread all over Europe would be quite a reliable source. The use of electric vehicles will open new possibilities to variable and intermittent power production. Producing fuel for vehicles that are only used about 1,000 hours per year will ease the flexibility needs in power systems.

The expected developments of wind power technology will affect the impact that wind power has on the power systems. Very large wind farms (hundreds of MW) are one trend that can pose serious challenges to the integration of wind power, as they concentrate the capacity. As a result, the smoothing effect of variations by geographical spreading is lost. However, the large wind farms will also pave the way for other technologies that will help the integration. Increasingly sophisticated power electronics and computerised controls in wind farms, as well as an improved accuracy of wind forecasts will lead to improvements in the predictability and controllability of wind power. Large wind energy power plants will mean that there are new requirements regarding the integration of wind power into the power system. Increasingly, wind farms will be required to remain connected to the system when there are faults in the system. They will be expected to withstand nearby faults without experiencing problems in power production during and after the faults. And they will be expected to provide reactive power support to the system during the fault.

8.5 Conclusions

Wind power will have an impact on power system reserves as well as on losses in generation and transmission/distribution. It will also contribute to a reduction in fuel usage and emissions.

Regarding the power system, the drawbacks of wind power are that wind power production is variable, difficult to predict and cannot be taken for given. However, integrating variable sources is much less complicated if they are connected to large power systems, which can take advantage of the natural diversity of variable sources. A large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output. The power system has flexible mechanisms to follow the varying load that cannot always be accurately predicted. As no production unit is 100 % reliable, a part of the production can come from variable sources, with a similar risk level for the power system.

[12] See Chapter 9.

Power system size, generation capacity mix (inherent flexibility) and load variations have an effect on how intermittent production is assimilated into the system. If the proportion of intermittent power production is small, and wind power production is well dispersed over a large area, and correlates with the load, wind power is easier to integrate into the system.

Short-term, mainly the variations in wind power production affect power system operation. This refers to the allocation and use of extra reserves as well as cyclic losses of conventional power production units, and transmission/distribution network impacts. The area we have to look at for intra-hour variations is the synchronously operated system. In a large system, the reserve requirements of different loads and wind power interact and partly compensate each other. The power system operation then only needs to balance the resulting net regulation. The variability introduced by wind power will not be significant until variations are of the same order as the variability of the random behaviour of electricity consumers. On the time scale of seconds/minutes (primary control), the estimates for increased reserve requirement have resulted in a very small impact. On the time scale of 15 min to 1 h, the estimated increase in reserve requirement is of the order of 2–8 % of installed wind power capacity, when wind energy penetration level is 10 %.

Long-term, the expected wind power production at peak load hours has an impact on the power system adequacy. It is expressed as the capacity credit of wind power. For a low system penetration, the capacity credit equals that of a completely reliable plant generating the same average power at times when the system could be at risk. As the penetration increases, variable sources become progressively less valuable for saving thermal capacity.

There are no technical limits to the integration of wind power. However, as wind capacity increases, measures have to be taken to ensure that wind power variations do not reduce the reliability of power systems. There will be an increasing economic impact on the operation of a power system if wind power penetration exceeds 10 %.

Large-scale wind power still lies in the future for many countries, and there are long-term trends that can influence what impact wind power has on the system, like the use of electricity for vehicles, for instance. At high penetration levels, an optimal system may require changes in the conventional capacity mix.

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Research Article

Hourly Wind Power Variations in the Nordic Countries

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Key words: wind variations, wind power production, aggregated wind power, fluctuating prduction

Studies of the effects that wind power production imposes on the power system involve assessing the variations of large-scale wind power production over the whole power system area. Large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output. In this article the patterns and statistical properties of large-scale wind power production data are studied using the data sets available for the Nordic countries. The existing data from Denmark give the basis against which the data collected from the other Nordic countries are benchmarked. The main goal is to determine the statistical parameters describing the reduction of variability in the time series for the different areas in question. The hourly variations of large-scale wind power stay 91%–94% of the time within ±5% of installed capacity in one country, and for the whole of the Nordic area 98% of the time. For the Nordic time series studied, the best indicator of reduced variability in the time series was the standard deviation of the hourly variations. According to the Danish data, it is reduced to less than 3% from a single site value of 10% of capacity. Copyright © 2005 John Wiley & Sons, Ltd.

Introduction

Integration of wind power in large power systems is mainly subject to theoretical studies, as wind power penetration levels are still modest. Even though the penetration in areas such as West Denmark is already high (about 20% of yearly electricity consumption), wind power represents only 1%–2% of the Nordel and Central Europe (UCTE) systems.

Wind power production is characterized by variations on all time scales: seconds, minutes, hours, days, months and years. Even the short-term variations are to some extent unpredictable. These are the main reasons why large-scale wind power production poses a challenge to the rest of the energy system.

For the power system the relevant wind power production to study is that of larger areas. This means large geographical spreading of installed wind power, which will reduce the variability and increase the predictability of wind power production. Not taking this into account can result in an exaggeration of the impacts of wind power.

This study is based on existing production data on an hourly level. Detailed statistical analyses of hourly wind power production are presented. The aim is to see how large-scale, regional wind power production looks compared with the production of a single wind farm and, going further, how wind power production from the whole Nordic area looks compared with the production from one country only.

The installed wind power capacity at the beginning of year 2003 was 2200 MW in West Denmark,[1] 573 MW in East Denmark,[2] 345 MW in Sweden,[3] 97 MW in Norway[4] and 41 MW in Finland.[5] In Denmark, system integration of wind power is already a reality, whereas in other countries it is still a subject for discussion.

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Previous Work and Scope of This Study

The extent of wind power variability has been the subject of several studies. European meteorological station wind data for 1 year have been used in two studies, though not covering all the Nordic countries.[6,7] In The Netherlands a detailed analysis of wind speed data was done including variability and persistence.[8] In Ireland and France the variations of dispersed wind power production have been studied with wind speed data across each country.[9,10] For the Nordic countries a study based on Reanalysis (weather prediction) long-term 12-hourly wind speed data was made looking at the longer variations and correlation of production.[11] For Finland, yearly and monthly wind power variations were studied in Reference 12 and 3-hourly variations based on data for five geographically dispersed weather stations in Reference 13.

All the studies above have been based on wind speed data from several geographically dispersed measurement masts, converting wind speeds first to higher altitude (hub height of wind turbines) and then to the production of a single wind turbine using a power curve. There are possible caveats firstly in upscaling the wind to higher altitudes, as the wind profile is dependent on atmospheric conditions,[8] and secondly in using a single-point measurement to represent a wind farm stretching from one to several kilometres in dimensions.

Studies based on wind power production are scarcer owing to the fact that large-scale wind power production has only started to emerge in the past few years. In The Netherlands the variability and persistence of dispersed wind farm data of 250–500 kW turbines[14] confirm most of the wind speed data analyses of Reference 8, but an indication of somewhat less variability when using wind turbine data can be seen. In Germany, statistical analyses from production and measured wind speed data have been made in conjunction with a comprehensive 10 year follow-up project of the 250 MW programme.[15,16] Annual, seasonal, diurnal and hourly variations are one result of this activity. Faster measurements of these data were further analysed to look at the trends of power fluctuations as well as fast regulation needs of wind power.[17] Fast ramp rates (from 1 s to 1 h) for a large wind farm have been recorded in the USA.[18,19] For power system impact studies, wind farm data have been used;[20–22] however, often the problem has been to get enough wind power production data to represent the whole of the area in question, as well as getting synchronous data from both the electrical load and wind power production. The representativeness of the data, especially for the variations of wind power production, is crucial for the studies, as upscaling too few data series to large-scale wind power production will also upscale the variations, not taking into account the smoothing effect.[23] A study of the smoothing effect and its saturation has been made for the Northern part of Germany.[24] To take into account the smoothing effect, extrapolation of statistical parameters has been used,[25] as well as preprocessing of wind power data by sliding averages.[26]

This work is based on a data set of realized hourly wind power production values from three example years. The study is mainly concentrated on the extent of wind power hourly variations, and the results can be used to assess the impacts on the secondary reserve or hourly load-following reserve of the power system (dealt with in the second part of this study[27]). It is common sense as well as proven by earlier studies that geographical spreading of wind power will reduce variability. However, the quantification of this phenomenon is not straightforward. This is a relevant research topic in itself, needed in order to determine what kind of input data for wind power should be used when studies of wind power in power systems are made.

Data Used in This Study

The data used in this study are the measured output of wind power plants and wind parks (Figure 1). Realized hourly wind power production time series from the four Nordic countries were collected. Data were collected for years 2000–2002.

To compare the data sets of different installed capacity, they were represented as relative production, as % of installed capacity:

$$p_i = \frac{P_i}{P_{\mathrm{TOT}}} \tag{1}$$

Figure 1. Data for hourly wind power production were available from 21 sites in Finland, six sites in Sweden, 6–12 sites in Norway (the lighter-coloured sites only for part of the time) and the aggregated total production of hundreds of sites in West and East Denmark

where p_i is the relative production for hour i as % of capacity, P_i is the production MWh h^{-1} for hour i and P_{TOT} is the installed capacity.

For wind power production time series in Finland, Sweden and Norway the available data represented far less than 100 MW of capacity. This means that these time series had to be upscaled more than 10-fold to make large-scale wind power production time series for the countries. Upscaling the hourly values means upscaling also the hourly variations. Real large-scale wind power production would mean that the output would be smoothed out by hundreds or thousands of turbines located at tens or hundreds of sites. An example of the problem is illustrated in Figure 2, taken from real data in Denmark. This is why several geographically dispersed sites were looked for to make the aggregate time series for the countries. Also hourly wind speed measurement data were used to complement the production data for Finland, Sweden and Norway. There were two wind speed series for Finland and one for Sweden. Most of the data for Norway were wind speed time series. An effort was made to make single-point measurement data represent wind farm production when wind speed was converted to wind power production. First the wind speed was smoothed out by taking a 2 h sliding average for each hour. This smoothed wind speed was converted to power production using an aggregated, multi-turbine power curve (Figure 3).[28] The data handling principles are described in more detail in Reference 29.

The Nordic data set was formed from the data sets of all four countries. The production at each hour was a simple average of the % of capacity production of the four countries. In terms of capacity this would mean setting for example 3000 MW in each country, a total of 12,000 MW. This is somewhat theoretical, as Denmark

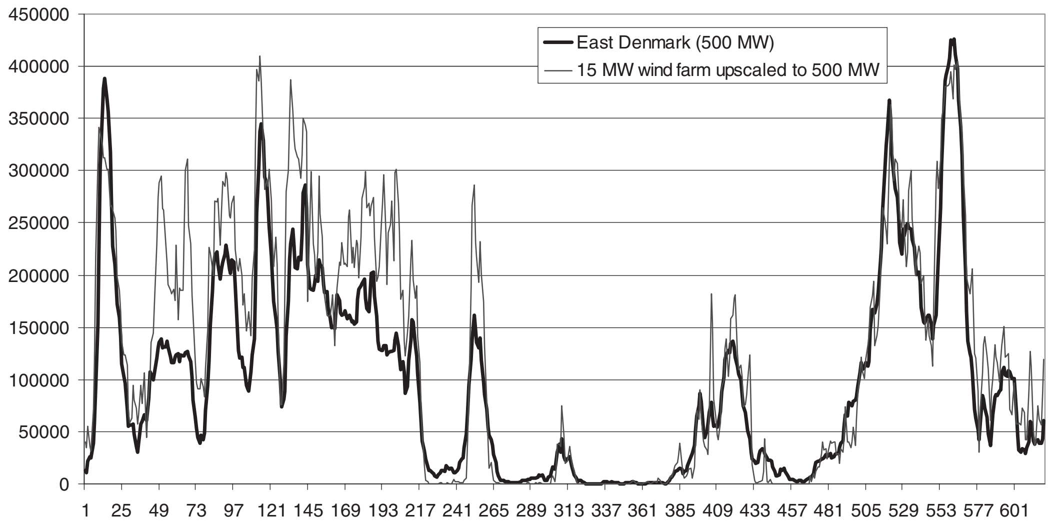

Figure 2. An example of wrong upscaling: a single site would see more variations, peaks and calms than dispersed, large-scale wind power production (here 500 MW, 200 × 100 km²)

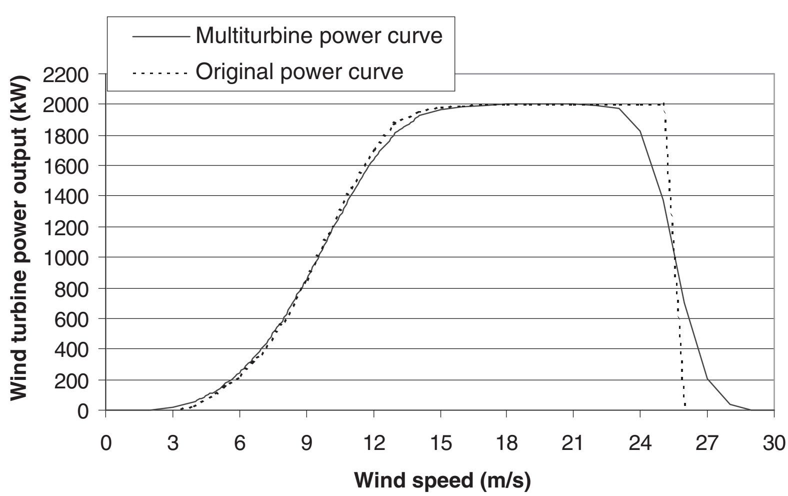

Figure 3. To convert the wind speed time series to wind farm power production, a multi-turbine power curve was used, smoothing out the production near the cut-in (3 m s^{-1}) and cut-out (25 m s^{-1}) wind speeds compared with a single-turbine power curve

is now dominating the installed wind power and probably will be for quite some time, even though the wind energy potential is probably as large in all four countries taking into account the offshore potential. Also a time series called 'Nordic 2010' was formed where half of the capacity is in Denmark.

Data set for Finland

By courtesy of 10 wind power producers and two power companies with wind speed measurements for high masts, wind power production data were available from a total of 55 turbines at 21 sites and wind speed data were available from two sites (on the Internet[30]).

The maximum distance between the sites is 1000 km North–South and 400 km West–East. As the data were used to represent large-scale wind power production, they were upscaled. To represent the geographical distribution of potential wind power production in Finland, Lapland and the South coast were reduced to a tenth of total capacity each, and the West coast was given the bulk of wind power production: 400 MW in the Gulf of Bothnia South and 400 MW in the Gulf of Bothnia North.[29]

Data set for Sweden

For Sweden, wind power production data were acquired from two sites in South Sweden (West and South coast), one by the large inland lake Vättern and the other on the island of Gotland (East coast), and one site in North Sweden by the East coast. From the Northern part, also one wind speed measurement time series was acquired.[31] The maximum distance between the wind power data sites in Sweden is 1300 km North–South and 400 km West–East.

For upscaling, 80% of capacity was assumed in South Sweden and 20% of capacity in North Sweden.

Data set for Norway

For Norway, wind power production data were acquired from one site. However, the data had missing periods, especially for year 2001. Two wind speed measurement time series were acquired from potential wind power sites in Middle and South Norway covering part of year 2000.[32,33]

Norwegian meteorological institute (NMI) data were well representative for wind power production: it is measured hourly and with high average wind speeds. Five sites along the coastline were used for 2000–2002, and additionally six sites for year 2001.

Norway is the largest country when considering the largest dimensions between the potential wind farm sites: about 1400 km North–South and 700 km West–East.

For upscaling, Norway was divided into three regions, first aggregating the available data as simple averages per site for each of South, Middle and North Norway. The total wind power production was also a simple average: the same amount of wind power was assumed for South, Middle and North Norway.

Data set for Denmark

For Denmark the system operators Eltra (West Denmark) and Elkraft System (East Denmark) have hourly production data available at their Internet sites, starting from year 2000.[1,2] Also some subarea data (15–60 MW) were available for East Denmark in 2001, courtesy of Elkraft System. The maximum distance between the sites in West Denmark is roughly 300 km North–South and 200 km West–East. For the Eastern part the dimension is about 200 km North–South and 100 km West–East. Bornholm island, south of Sweden, is a part of East Denmark.

The Danish data represent the realized production of thousands of turbines and hundreds of sites. However, there has been a significant increase in wind power capacity from 1730 MW at the start of 2000 to 2612 MW at the end of 2002 (Table I).

To be correct in converting the hourly production in MWh h^{-1} to relative production, as % of capacity, exact data on each wind farm's network connection would be needed. This means making an hourly P_{TOT} time series

Table I. Installed wind power capacity (MW) at the start of the year in Denmark

Year	Denmark, West	Denmark, East	Denmark, total
2000	1340	390	1730
2001	1790	503	2293
2002	1970	554	2524
2003	2040	572	2612

in equation (1), P_{TOTi}. If the information on capacity addition (or reduction, as some old wind turbines have been taken from operation) was not correct, a step-up in the MW time series at a wrong hour could distort the real production time series. This would either add more variations or damp the real variations from one hour to the next.

Daily data on capacity development in East Denmark were obtained for years 2001 and 2002. For West Denmark, and for year 2000 in East Denmark, no exact data on capacity were available. For these data sets an approximate hourly MW series has been constructed to convert the data to % of capacity. For West Denmark the capacity has been rising at an average rate of 50 kW h^{-1} in 2000 and 13 kW h^{-1} in January 2001, after which a constant capacity has been used, until a rise in November/December 2002 of 48 kW h^{-1}. The large offshore wind farm at Horns Rev was started in December 2002. However, owing to low availability during the first testing period, this 160 MW was not taken as an increase in the installed capacity in this study. For East Denmark the capacity has been rising at an average rate of 16 kW h^{-1} in 2000. The maximum rise of capacity, in the daily capacity data of East Denmark, is 17·8 MW in 2001 and 11·5 MW in 2002.

Looking at the capacity increase in Denmark,[1,2] it has been quite linear. The difference between the approximation used here and real life would stay below 20 MW at any hour. The errors for the hourly variations are even smaller, as the capacity increase in practice comes as one to three turbines at a time when the test operation of a wind farm starts. Assuming a maximum 10 MW instantaneous capacity increase in an hour, this would be seen as an error of 0·5% of capacity in the hourly variation, either overestimating an upward variation or underestimating a downward variation in the data set used in this study. The error is very small in the situation where there is in real life no increase in the capacity from one hour to the next—an assumed 60 kW increase in capacity is 0·003% of the total capacity at the beginning of year 2000 and 0·002% at the end of year 2002.

Large-Scale Wind Power Production

Large-scale wind power means the production of hundreds (or thousands) of turbines at tens (or hundreds) of sites. Geographical spreading of production evens out the total production from an area. The smoothing effect can be seen from the statistical analyses presented in this section. Examples of the data sets in this study are shown in Figure 16 (see Appendix) for February 2000.

Basic statistics of the wind power production data used

The basic statistics of the yearly time series are presented in Table II. Wind power production statistics from the four countries and their combination are shown. As a comparison, data from a single site in Finland are also shown. For stall-regulated turbines the maximum power can exceed the nominal capacity, especially in cold weather.[34]

Table II. Descriptive statistics of hourly wind power production in the Nordic countries for years 2000–2002. Wind power production is presented as relative production as % of installed capacity. The width of the areas is presented as largest distance North–South (NS) and West–East (WE)

Statistic	Single site	Denmark	Finland	Norway	Sweden	Nordic
Largest distance NS/WE (km)	—	300/300	1000/400	1400/700	1300/400	1700/1100
Mean (%)	25·9	22·2	22·3	32·3	23·5	25·1
Median (%)	14·9	14·6	17·5	29·2	18·6	22·4
Standard deviation (%)	28·2	21·2	17·6	19·6	18·3	14·5
Standard deviation/mean	1·09	0·95	0·79	0·61	0·78	0·58
Range (%)	105·0	92·7	91·1	93·0	95·0	85·4
Minimum (%)	0·0	0·0	0·0	0·0	0·0	1·2
Maximum (%)	105·0	92·7	91·1	93·1	95·0	86·5

First of all, the difference in wind resource is notable: Norway has an excellent wind resource, with an average production of 32% of capacity compared with 22%–24% for the other Nordic countries. Over the years, average production varies between 31% and 34% of installed capacity in Norway and between 22% and 25% of capacity in the other countries.[35] Denmark has here the lowest production rates as % of capacity. This is probably due to the data including also inland sites and sites with older turbines with 20–40 m towers: the rotors are not reaching as good a wind resource as the new, 60–100 m high MW-scale turbines. The production here does not yet have large offshore wind power included, with better wind resource (two 160 MW wind farms erected in late 2002 and 2003).

The median is the value in the middle when sorting all the values in increasing or decreasing order. For wind power production it is typical that the median is lower than the mean value. Most of the time the production is less than average. When aggregating production from a larger area, the median gets closer to the mean value.

The smoothing effect can be seen in the range of production, the maximum and minimum encountered during the years. Duration of calms will be substantially decreased, as the wind blows almost always in some part of the system area. Maximum production level will not reach installed nominal capacity, as the wind will not blow as strongly at all sites simultaneously, and of hundreds or thousands of wind turbines not all are technically available at each instant. For the total Nordic time series the production never goes to zero; however, the lowest production is only 1% of installed capacity. The maximum production from geographically dispersed wind power production stays under 90% for the Nordic countries. Even if we are talking about large-scale wind power production, the production range will still be large compared with other production forms: maximum production will be three to four times the average production, depending on the area (Table II).[11]

Another trend of smoothing can be seen in the standard deviation values. The standard deviation σ reveals the variability of the hourly time series, it is the average deviation from the mean value μ:

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

For a single turbine the standard deviation is somewhat larger than the mean, about 30% of capacity (nearly 40% for some sites in Norway). For a country the standard deviation gets closer to 20% of capacity. For larger countries such as Norway, Sweden and Finland, where the sites are spread 1000 km apart, the standard deviation is less than 20%. For the total Nordic time series the standard deviation is close to 15% of capacity (Table II). The standard deviations for European data derived from wind speed measurements suggest that the standard deviation relative to the mean value is 0·5–0·8 for a circle of radius 200 km and 0·4–0·6 for radius 1000 km, and the smoothing effect saturates at about 0·3 when the radius gets larger than 2000 km.[7]

Frequency distributions of wind power production

To take a closer look at wind power production, the hourly production is plotted as a frequency distribution in Figure 4.

It can be seen in Figure 4 that large-scale production of wind power means shifting the most frequent ranges from low production to near average production. For a single site the production is almost half of the time below 10% of capacity. For the wind power scattered to all Nordic countries, the production is most of the time between 5% and 30% of capacity and is seldom below 5% or above 70% of capacity.

The probability of wind power production can also be presented as a duration curve. In Figure 5 the Nordic wind power production for year 2000 is shown chronologically (the varying curve) and as a duration curve, where the production values are sorted in descending order before drawing the curve. In Figure 6 the smoothing effect is presented as duration curves.

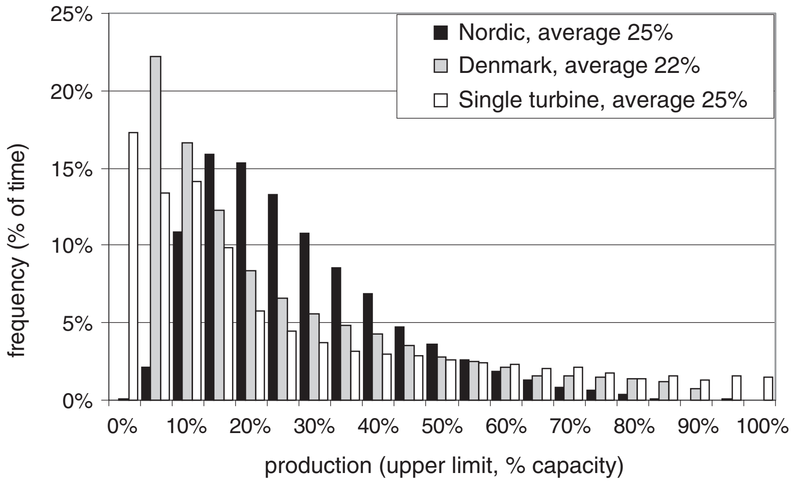

Figure 4. Frequency distribution of wind power production from one site, from a country and for a theoretical total Nordic production. Example years 2000 and 2001. The production values on the x-axis denote the upper value of the range

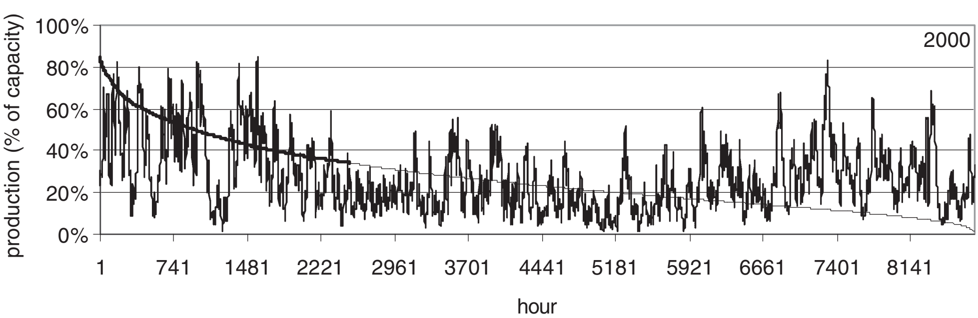

Figure 5. Example of data for this study: the total Nordic wind power production as a chronological time series and as a duration curve

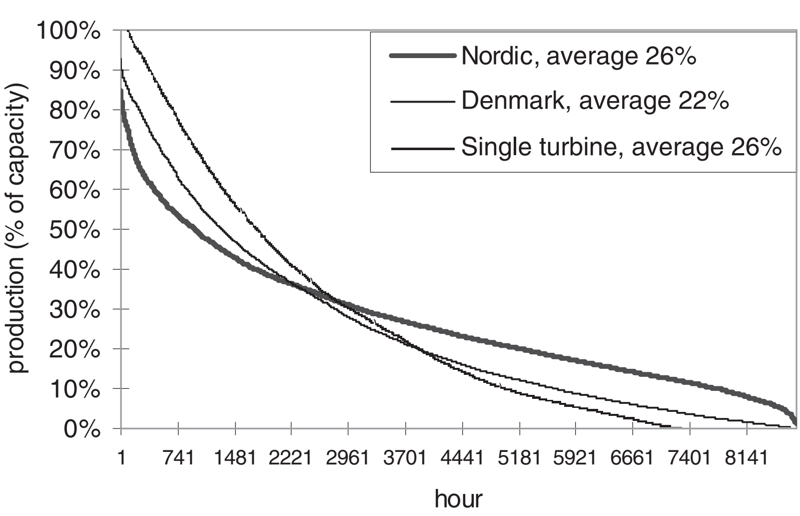

Figure 6. The effect of geographical spreading is to flatten the duration curve of wind power production. Example of year 2000 hourly data, where wind energy distributed to all four Nordic countries is compared with one of the wind farms and one of the countries (Denmark). Average production for the curves is denoted in the legend text

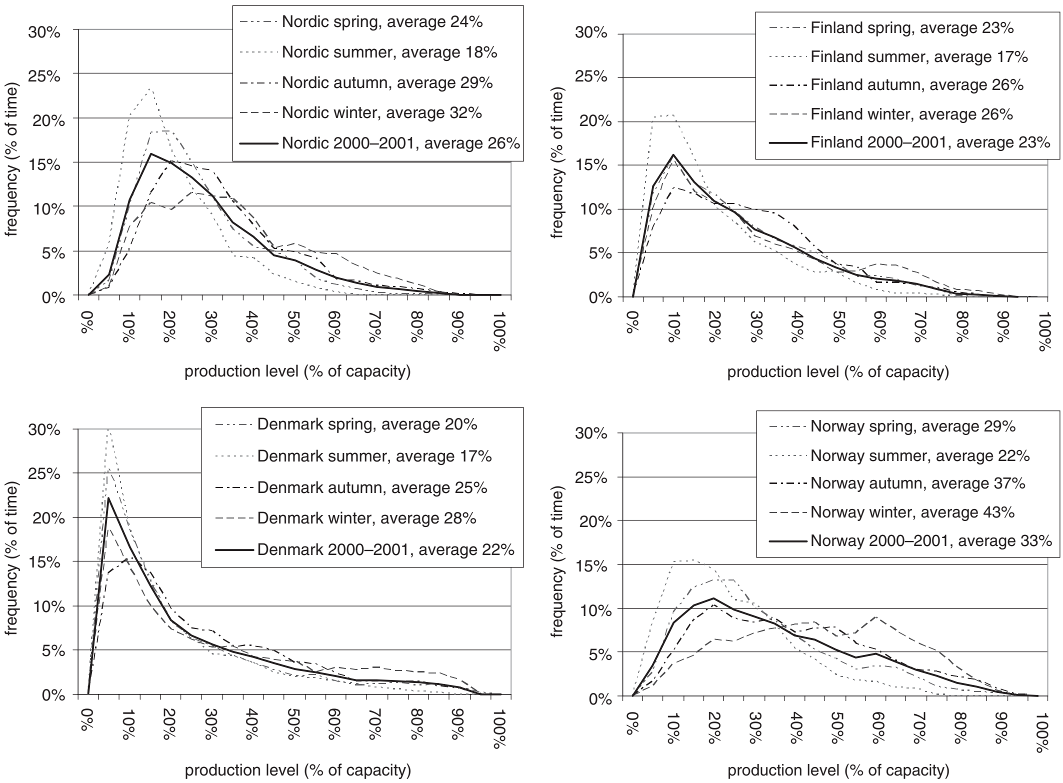

Figure 7. Difference in frequency distributions of wind power production for seasons: the lower production levels have a higher probability in summer, and higher production levels are more probable in winter. Average production during the seasons is denoted in the legend text

Seasonal variation of wind power production

In Central and Northern Europe there is a distinct seasonal variation in wind power production: more production in winter than in summer. The production during the summer months is 60%–80% of the yearly average, while the production during the winter months is 110%–150% of the yearly average, according to these data for years 2000–2002.

This is also reflected in the range of production values, for example, the hourly data for the Nordic countries for years 2000 and 2002 range between 1% and 61% in the summer and between 2% and 85% in the winter.

Frequency distributions for the four seasons are presented in Figure 7. Duration curves for summer and winter are presented in Figure 8 for Denmark and the combined Nordic wind power production.

Diurnal variation of wind power production

Wind is driven by weather fronts and a daily pattern caused by the sun, so, depending on whether one or other of these dominates, there is either a significant or hardly any diurnal pattern in the production. In Europe there is a tendency for winds to start blowing in the morning and calm down in the evening (Ireland,[9] Germany[16]). In Northern Europe this is more pronounced during the summer (Figure 9).

In winter there is no clear diurnal variation to be seen, except for a slight one in Denmark (the uppermost curve in the Figure 9 graph for Denmark). In summer the average production between 11 : 00 and 18 : 00 is above 20% of capacity, compared with less than 15% of capacity during the night. The diurnal variation here

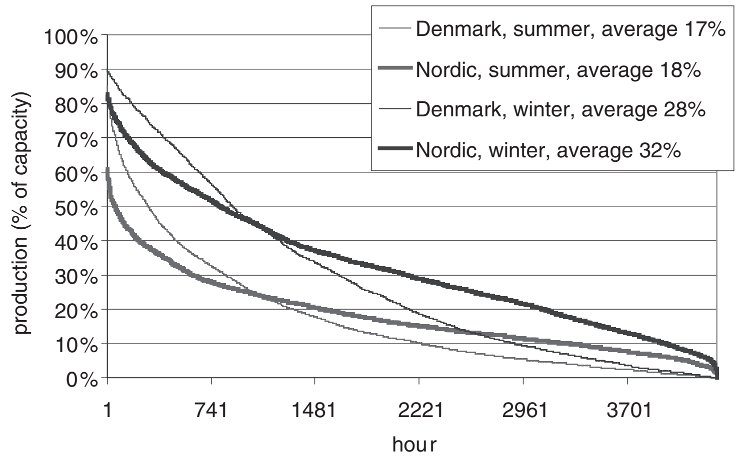

Figure 8. The wind power production is higher during the three winter months (upper curves: January, February and December) than during the three summer months (lower curves: June, July and August). Duration curves for production in 2000 and 2001

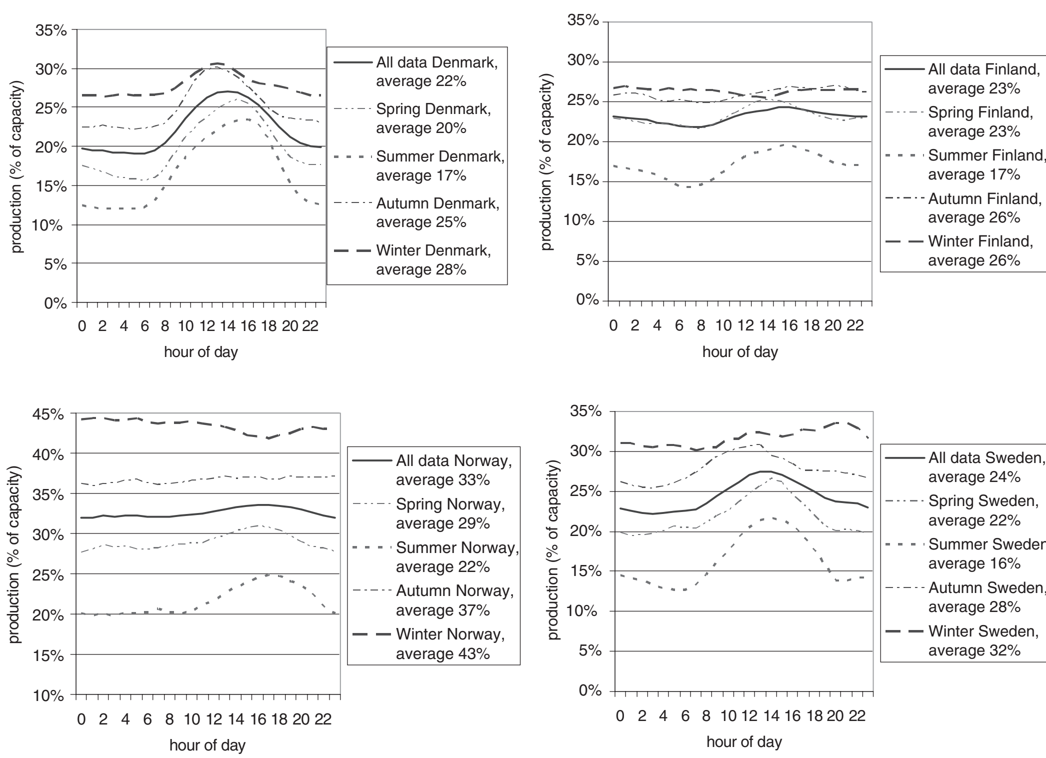

Figure 9. For the Nordic countries, diurnal variation is more pronounced in summer

is presented in Central Europe time, as used in Denmark, Norway and Sweden. The hours have a shift for summer time in the spring and back to normal time in the autumn.

Wind power production in Denmark and Sweden experiences a more pronounced diurnal variation, whereas the sites in the Northern parts of Finland, Sweden and Norway do not experience any detectable diurnal variation, which has also been observed before for Norway.[36]

Persistence of wind power production

Frequency distributions and duration curves give some idea of how often certain production levels occur. However, for a varying power production such as wind power, persistence of different production levels is also of interest—how long does a certain production level last? There are two special cases presenting the greatest challenges in integration of wind power into the system: duration of calms or low wind power production, and occurrence of peaks, which are especially pronounced in wind power production.

Duration of calms has here been defined as the time when wind power production is less than 1% of capacity. As the average production is of the order of 20%–25% of capacity, this can also be put as about 4%–5% of average production. Additionally, low-production persistence has been studied, i.e. when wind power production is less than 5% of capacity (roughly 20% of average production). A production level of 10% of capacity is already almost half the average production, and wind power production is almost a third of the time below the 10% level (for the total Nordic production, almost 15% of the time; Figure 6).

In Denmark the production was below 1% of capacity nearly 5% of the time (4·6%, 4·9% and 6·0% of the time in 2000, 2001 and 2002 respectively), whereas for the larger areas of Finland and Sweden, this occurred 1%–2% of the time. For Norway, calms were very rare (0·1%, 0·3% and 0·8% of the time in 2000, 2001 and 2002 respectively). The longest duration of calm (production below 1% of capacity) for Denmark was 58 h in 2002 and 35 h in 2000. For Finland and Sweden it was 19 h and for Norway 9 h. For the total Nordic data set there were no totally calm periods, the production always being above 1% of capacity.

The longest duration of low production, less than 5% of capacity, was 95 h for Finland and Denmark and less than 50 h for Norway, Sweden and the total Nordic time series. The longest periods occurred during spring/summer months (April–August). For the Nordic time series the production was below 5% of capacity 2%–3% of time.

Peak production was here studied for the level of above 75% of capacity. As the average production is of the order of 25% of capacity, this can also be defined as roughly three times the average production. The longest periods with high wind power production exceeding 75% of capacity were 27–38 h in the countries and 14 h for the total Nordic data.

Correlation of wind power production

Cross-correlation ($r_{x,y}$) is a measure of how well two time series follow each other:

$$r_{x,y} = \frac{\frac{1}{n}\sum_{i=1}^{n}(x_i - \mu_x)(y_i - \mu_y)}{\sigma_x \sigma_y} \tag{3}$$

where μ denotes the average, σ the standard deviation and n the number of points of the time series. Cross-correlation is near the maximum value 1 if the ups and downs of the production occur simultaneously, near the minimum value −1 if there is a tendency of decreasing production at one site and increasing production at the other site, and close to zero if the two are uncorrelated and the ups and downs of production do not follow each other at the two sites. When distributing wind power production to a larger area, the total production will be smoother and less variable if the correlation between the sites is low.

Correlation can also be calculated for a single time series but with time lags. This is called autocorrelation. For wind power production the autocorrelation decreases soon with increasing time lag; already at 12 h lag the correlation becomes weak.[37]

The cross-correlations were calculated for all sites in the Nordic countries for one year, 2001, when the data available included most sites, altogether 33 time series. Some of the time series were aggregated production data from a larger area, for which the co-ordinates were estimated from the centre of the area. The results are presented in Figure 10. The cross-correlation decreases fast at first, $r_{x,y} = 0{\cdot}7$ for a distance of about 100 km and 0·5 for a distance of about 300 km, after which the decrease is slower.

There is significant variation in the cross-correlation coefficients for a similar distance, as expected. The correlation becomes weak, below 0·5, with distances above 200–500 km. When local phenomena influence the

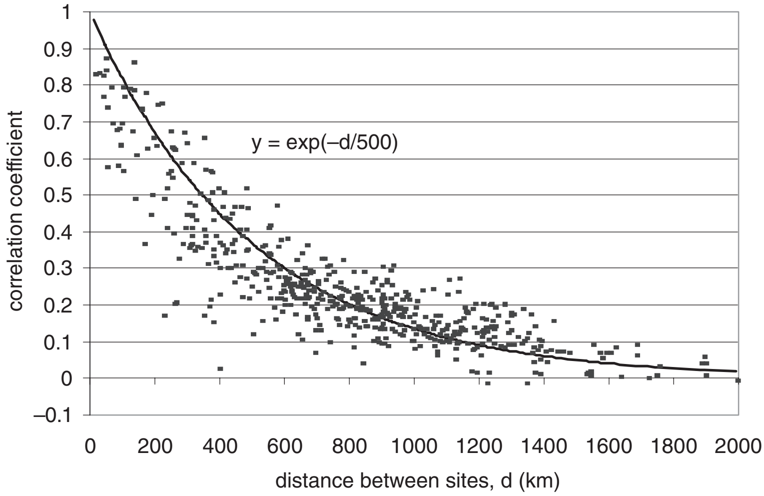

Figure 10. Cross-correlation coefficients for the sites of the Nordic data for year 2001

wind resource, the winds do not correlate with sites even some 200 km apart. The lowest points in Figure 10 for distances of 200–800 km come from the westernmost site in South Norway, for which the correlation with all other sites is weak. In Figure 10 the lowest cross-correlations are slightly negative, for Finnish Lapland with South Norway sites. Slightly negative correlations between two points in Europe have been reported for weather data from Ireland/Portugal (1500 km apart) and Spain/Greece (3000 km apart).[7] The results from correlation between weather station wind speed-based data calculated from 9 years in Finland are similar to the ones here for year 2001.[13] There is no significant change in correlation coefficients calculated from different years. A year of hourly data contains enough different weather situations to be able to determine the correlation between the wind power production at different sites.

The cross-correlation can be modelled by exponential fitting, decay parameters (D) of 500–700 have been reported.[7] For the present data, $D = 500$ fits them (Figure 10).

Looking at large-scale wind power production for the four countries, Swedish and Danish wind power production is correlated, $r_{x,y} = 0{\cdot}71$ (assuming that most of the Swedish wind power is in the Southern part). Wind power production in the other countries is only weakly correlated, $r_{x,y} = 0{\cdot}42$–$0{\cdot}45$ for Sweden/Norway/Finland and 0·22–0·33 for Denmark/Finland, Norway.

Taking a closer look at the regions in the Nordic countries, there is practically no correlation between Lapland (North Norway, Sweden and Finland) and the Southern areas (Denmark, South Sweden, Norway and to some extent South Finland).[29]

Short-term variations of wind power production

For power system operation the variations from day to day, from hour to hour and from minute to minute are of interest. The larger the area, the longer time scales are affected by the smoothing effect. Within a wind farm, all the wind turbines will experience different gusts (seconds), but the hourly wind power production will see approximately the same ups and downs. In a larger area covering several hundred kilometres, the weather fronts causing high winds will not pass simultaneously, but the good and poor months will occur at the same time. This can be seen in Figure 11, where the decreasing correlation of the variations is depicted for different time scales.[17] The correlation is here calculated for the differences between consecutive production values (ΔP). For the time series of production values (P) the correlation does not decrease as rapidly as shown in Figure 11, as can be seen from Figure 10.

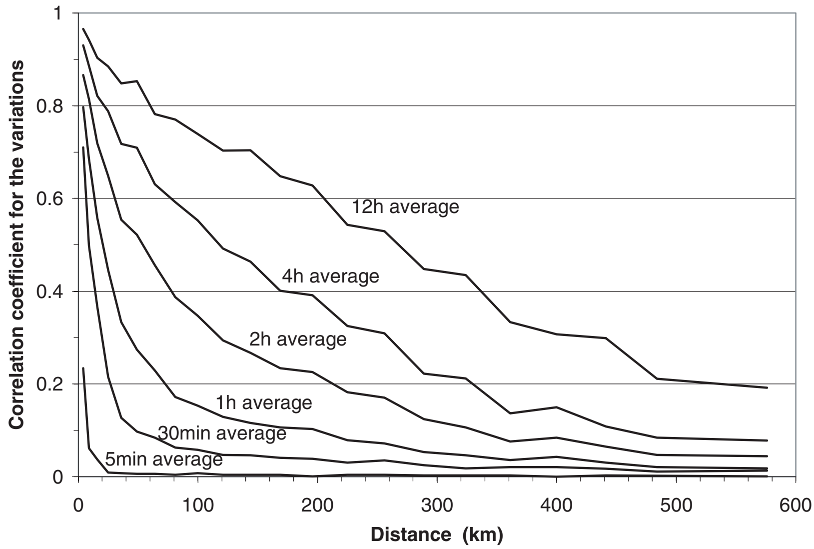

Figure 11. Variations will smooth out faster when the time scale is small. Correlation of variations for different time scales, example from Germany[17]

The Intra-hour Variations

Already the inertia of large rotating blades of a wind turbine will smooth out the very fast gusts of wind. For variable speed wind turbines the second-to-second variations will be absorbed in the varying speed of the rotor. For a wind farm the second-to-second variations will be smoothed out, as the same gusts will not occur simultaneously at all turbines, situated several hundred metres apart.

The extreme ramp rates recorded from one 103 MW wind farm are 4%–7% of capacity in a second, 10%–14% of capacity in a minute and 50%–60% of capacity in an hour.[18] These examples are from a limited area compared with system operation: a large wind farm or three smaller wind farms some 10 km apart. For a larger area of geographically dispersed wind farms the second-to-second and minute-to-minute variations will not be significant.

For the 15 min variations in Denmark, the production can vary by 8·4% of capacity six times per month, and the maximum is 11%.[38] This is not as much as for the hourly variations, as seen in the following subsection.

There are means to reduce the fast variations of wind power production. Staggered starts and stops from full power as well as reduced (positive) ramp rates could reduce the most extreme fluctuations, in magnitude and frequency, over short time scales.[39] This 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 terms of cost-effectiveness.

The Hourly Variations

The hourly variation is here defined as the power difference between two consecutive hours. It is here measured relative to the nominal capacity, to compare it among several countries with different amounts of installed capacity:

$$\Delta P_i = P_i - P_{i-1}, \qquad \Delta P_i = P_i - P_{i-1} \tag{4}$$

For large-scale, dispersed wind power production there will be a significant smoothing effect in the hourly variations. The correlation of the variations between two wind turbines decreases faster than the correlation of the production. For hourly variations the correlation becomes weak already at distances less than 100 km

Table III. Largest hourly variations (%) of wind power production in the Nordic countries for years 2000–2002. Maximum variations are as % of installed capacity. The percentage of time that the variations are more than 5% or 10% of capacity is also presented

Country	Max up-variation	Max down-variation	Above 5%	Below –5%	Above 10%	Below –10%
Denmark	20	–23	4·5	4·4	0·6	0·5
Finland	16	–16	3·3	3·2	0·2	0·2
Norway	27	–29	8·7	8·6	1·5	1·3
Sweden	22	–27	6·7	6·5	1·0	0·8
Nordic, evenly	12	–11	0·7	0·6	0·0	0·0
Nordic 2010	13	–14	1·7	1·5	0·0	0·0

(Figure 11).[17] Correlations of hourly variations for the countries and areas within the countries were calculated and most of them were between –0·01 and 0·04, so there is no correlation between the hourly variations. Hourly variations in East and West Denmark are weakly correlated (0·46). For the other closest areas, South Sweden/Denmark, South Norway/West Denmark as well as the Western part of Finland, the correlation of variations is below 0·2.

The largest hourly variation is about ±30% of capacity when the area is of the order of 200 × 200 km^2 (e.g. West/East Denmark), and ±20% of capacity when the area is of the order of 400 × 400 km^2 (e.g. Germany, Finland and Iowa, USA). [15,40] For the Nordic data the largest hourly variations are 11% up and 10% down. For Norway and Sweden, despite the large area, the variations are higher than for Denmark and Finland (Table III). This is due to the limited number of sites included in the data sets. The Nordic variations are probably overestimated as a result of this.

These are the extreme values, most of the time the hourly variations will stay within ±5% of installed capacity (Figure 12 and Table III). It is notable that, as the average production is about 25% of capacity, this 5% of capacity represents 20% of average power. For the individual countries the hourly variations are more than 5% of capacity 6%–20% of the time. For Denmark this occurs 10% of the time, so probably the large variations of the Norwegian and Swedish data sets are due to too few time series in these countries to represent the variations correctly. Omitting Norway and Sweden, the conclusion is that the hourly variations of large-scale wind power production are 90%–94% of the time within ±5% of capacity and 99% of the time within ±10% of capacity. For the total Nordic time series the hourly variations are about 98% of the time within ±5% of capacity (Table III).

Theoretically, the largest variations of hourly wind power production occur owing to high wind speeds above the cut-off limit of the turbines (usually 25 m s^{-1}), when the production from individual turbines is reduced to zero from full power. However, for large-scale wind power production the turbines do not see the same high wind speed levels simultaneously. This is proved by the Danish data, where the largest down-variations are not more than 23% of capacity in Denmark and 26% of capacity in West Denmark. For the largest down-variations the initial production level in the countries was 70%–80% of capacity in most cases. There may well be some cut-off situations present in some of the areas where the initial production level was more than 90%.

Probability of significant variations is a function of production level. Significant changes occur most probably when wind farms are operating between 20% and 80% of capacity, as this is the steep part of the power curve when changes in wind speed produce the largest changes in power output of the turbines. For large-scale wind power the production is rarely above 80%, so an analysis of the Nordic data was done for the production level of above 20% of capacity (at the first hour). Hourly variations were analysed for these periods only, representing altogether about half of the data. The large variations occur nearly twice as often (relatively) for the countries when looking in this way, compared with the results for all data in Table III.[29]

Reduction in standard deviation for hourly time series is a measure of reduced variability in the time series with geographical dispersion of wind power. For North Germany the standard deviation of hourly time series

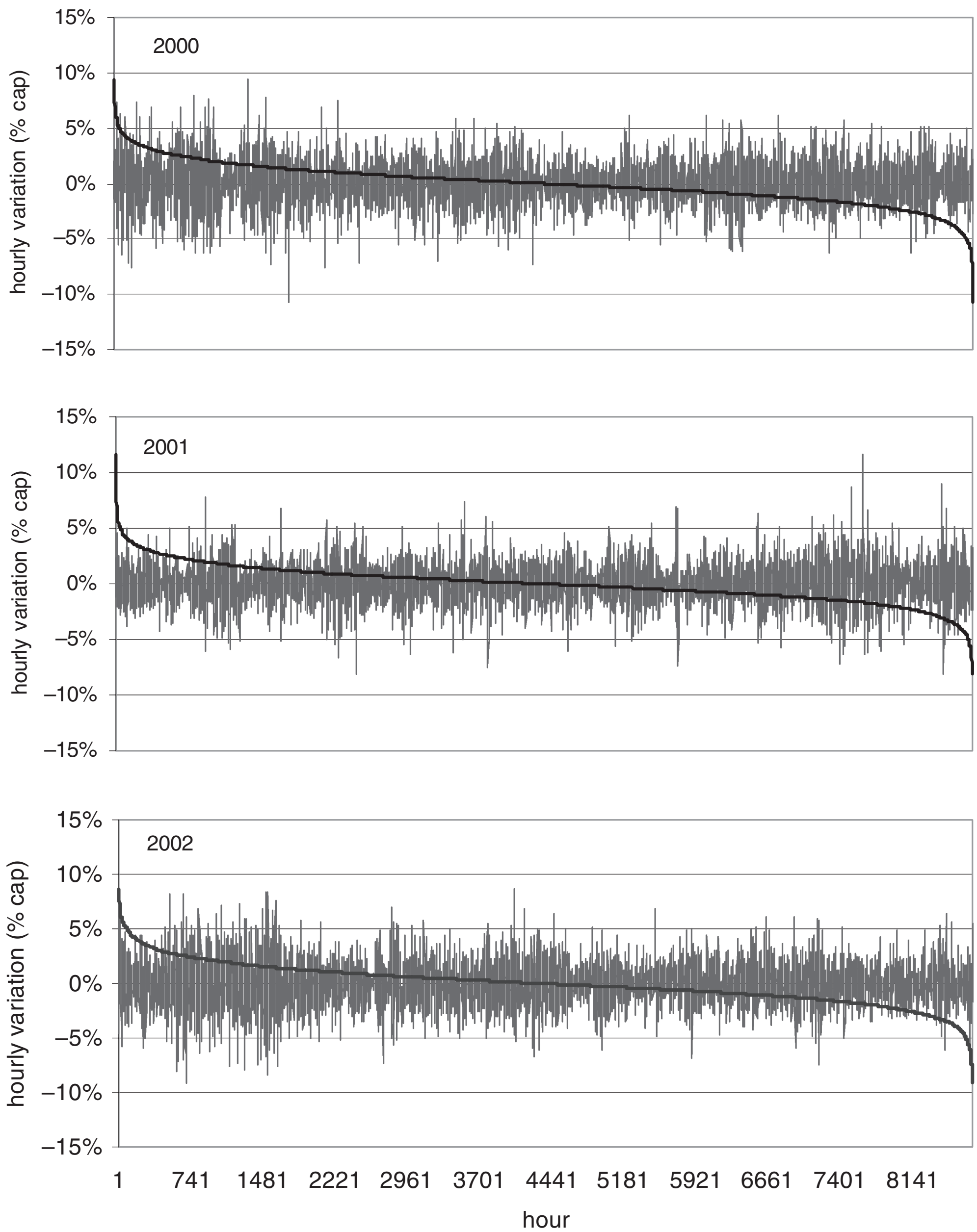

Figure 12. Hourly variations from Nordic wind power production, chronological time series and duration curve, years 2000–2002

will reduce to 70%–80% of the single-site value.[24] For the data set of Denmark the reduction is to 70% of the single-site value. For the data sets of Finland, Norway and Sweden there is more reduction, to about 60% of the single-site value. For the Nordic area the reduction is to about half of the single-site value ($\sigma = 14{\cdot}5\%$). For the more concentrated Nordic data set the reduction in standard deviation is to 60% of the single-site value.

The standard deviation of the time series of fluctuations ΔP will decrease even faster, from about 10% for a single turbine to less than a third (3%) for an area such as West Denmark.[23] For these data, Finland and

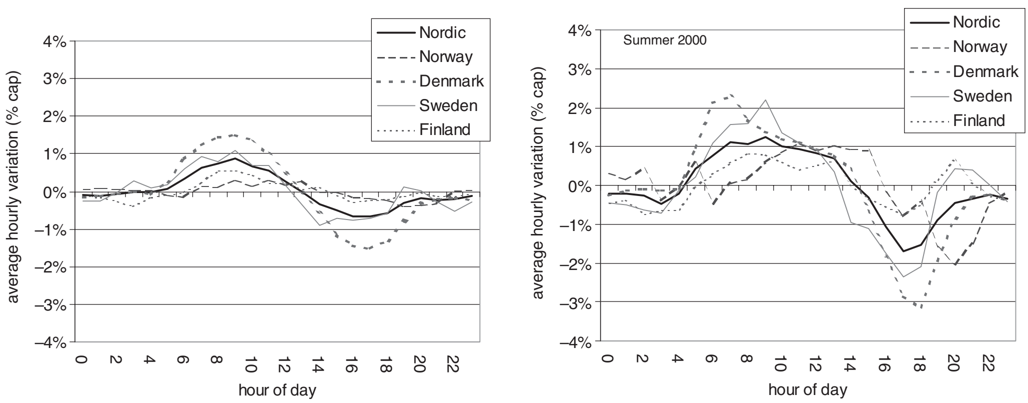

Figure 13. Diurnal dependence of hourly variations. All data and summer 2000

Denmark have the standard deviation of the time series of fluctuations ΔP lower than 3% and Nordic data lower than 2% of capacity.

Diurnal variations in output can help indicate when significant changes in output are most likely to occur.[19] The average hourly variations of wind power production are zero—there are as many up- as down-variations. However, when plotting the average hourly variation according to the time of day, the average is no longer zero for all hours of the day. There are more upward changes during the morning hours and more downward changes during the afternoon hours, as can be seen in Figure 13. This is more pronounced during summer, as is the diurnal variation of the production (see earlier). Also the maximum variations in the data set occur in the morning hours for the upward changes and in the evening hours for the downward changes. The maximum variations are less in summer according to these data; this is probably due to lower production levels in summer months.

Variations for Longer Time Scales

For longer time scales, i.e. 4–12 h variations, short-term prediction tools for wind power give valuable information on the foreseeable production levels and expected variations of wind power production.

From the Nordic data set the maximum 4 h variations are about ±50% of capacity for one country (for Denmark ±60% and for Finland ±40%). This has also been reported for a longer following period from Germany.[15] For the Nordic area it is ±35% of capacity according to this 3 year data set.

The maximum 12 h variation for the Nordic area is ±50% of capacity (for Denmark ±80% and for Finland ±70%). Taking larger areas, e.g. Northern Europe, and more years of data, a ±30% change in production 12 h ahead occurs about once a year.[11]

Representative Data for Large-scale Wind Power Production

To study the impacts of large-scale wind power production, the data should be representative in both time and space. Depending on what impact we are looking at, we should take an average year's production, or a low- or high-wind year, to see the extreme situations for system planning purposes. This means taking production from a representative time period to study. Depending on what impact we are studying, the wind power production time series should be representative for the area in question. For example, large-scale wind power impacts on the power system operation should involve the production from a large area, with a proper smoothing effect present in the data. This means taking production data from a representative space.

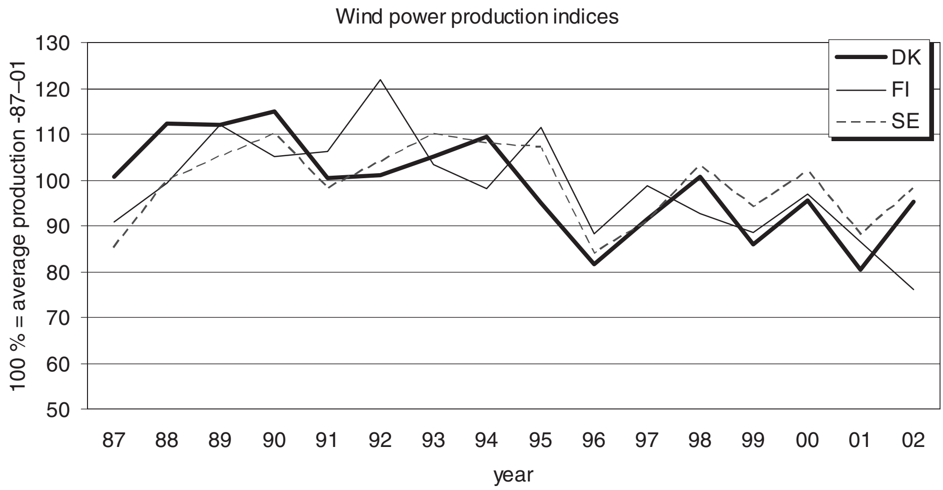

Figure 14. Yearly wind resource in 1987–2002 according to production statistics of wind energy in Nordic countries (DK = Denmark, FI = Finland, SE = Sweden)

Checking out the representativeness of the time period studied is quite straightforward when long-term wind power data exist. This is done in the following subsection. For checking the representativeness in geographical smoothing, in the second subsection some basic parameters from the previous section are picked up to form a guideline in this respect.

Representativeness of the study years

Here we look at the years in question: 2000–2002. Wind power production indices from national wind power production statistics are presented in Figure 14.[3,4,41] The wind power production index is a measure of one year's production compared with the long-term average production. A value of 100% means that the yearly production was equal to the long-term average. In Figure 14 it can be seen that the yearly production varies between 80% and 120%. In Finland the coastal areas South and West experience somewhat different wind resource variations; this is why the production indices are calculated for four sites.[4] The production indices for Finland are here calculated as weighted averages of these indices, using the large-scale wind power capacity distribution assumed in this study. For Norway this analysis was not done owing to a lack of long-term data. However, the Norwegian wind power production seems to experience the same trends as for the other Nordic countries, even if not as strongly.

Year 2000 was close to average (95% in Denmark, 97% in Finland and 102% in Sweden) and year 2001 was clearly less windy than average (80% in Denmark, 87% in Finland and 88% in Sweden). Year 2002 was close to average in Denmark (95%) and Sweden (98%) and a very-low-wind year in Finland (76%).

The production index can be used in determining the long-term average wind power production from only one year of realized production data, by dividing the year's production by the year's index value. Using the average production in 2000–2002 compared with the average production index for 2000–2002, we get roughly 24%–26% of capacity as the long-term average wind power production for Denmark, Sweden and Finland.

As a total period, 2000–2002 will give a production that is less than average: 90% of average production in Denmark, 87% in Finland and 96% in Sweden. However, as the data contain also high-wind months, e.g. the first part of year 2000 (monthly production indices in Reference 3, 4 and 41), there are also representative periods of high-wind situations in the data.

Representativeness of the geographical spreading of data

Based on the detailed statistical analyses, it can be estimated how well the data represent large-scale wind power production. The data used for wind power fluctuations are critical in the study of wind power impacts on power system operation. So as not to upscale the fluctuations when upscaling installed wind power in the system, the statistical characteristics for large-scale production should be looked for in any simulated or meteorological data-based wind power time series.[23] When enough turbines from a large enough area are combined, the smoothing effect reaches saturation and the time series can be upscaled with representative hourly variations.

As the Danish data are real large-scale wind power data from thousands of wind turbines, the comparisons made can be used as a basis to estimate how well the data sets constructed for Norway, Sweden and Finland represent large-scale wind power production.

Finland and Norway are considerably larger areas than Denmark, so also the smoothing effect should be stronger there. For Sweden there is the possibility of concentrating most of the wind power capacity south of Stockholm, which means that Sweden should get closer to the same smoothing effect as in Denmark.

Summing up the statistical properties for an hourly time series of large-scale wind power production, the following results were found.

- The standard deviation of the hourly production series should be less than the average production, slightly so for an area such as Denmark (300×200 km^2) and considerably so for a larger area: Finland 18%/22%, Norway 20%/34%, Sweden 18%/24%, Nordic 15%/25% (standard deviation/average, as % of capacity).
- The maximum hourly production should be less than 100%, 85%–95% depending on how large the area in question is: Denmark 93%, Finland 91%, Norway 93%, Sweden 95%, Nordic 87%.
- The duration of calms should be non-existent or limited: production below 1% of capacity 5% of the time in Denmark, 1%–2% of the time in Finland and Sweden, <1% of the time in Norway; minimum production in Nordic data set 1·2% of capacity.
- The standard deviation of the hourly variation series should be less than 3% of capacity: Denmark 2·9%, Finland 2·6%, Norway 3·9%, Sweden 3·5%, Nordic 1·7%.
- The hourly variations should be within ±20% of capacity, or even less if the area is larger than the size of Denmark: Denmark −23% to 20%, Finland −18% to 16%, Norway −21% to 27%, Sweden −20% to 22%, Nordic −11% to 12%.

When looking at the basic statistics for the production time series, there is no clear signal that the Norwegian and Swedish data would be unrepresentative, as taking even a few time series from the countries from different locations of the area gives a basic smoothing effect in the range of production. The analysis on the hourly variations, especially the standard deviation of hourly variations, reveals the caveats for the Swedish and Norwegian data sets.

For studies of wind power impacts on power system operation the variations of wind power production are crucial. To take a closer look at the representativeness of the variations in the time series, the smoothing effect measured as the reduction in standard deviation is studied in more detail. The smoothing effect is more pronounced with more turbines and more separation. The smoothing effect of a specified area has a limit; that is, the time series will not get smoother if more and more turbines are added from the same area. For Germany, for example, it has been estimated that 30 sites will be enough to get low variations, measured as the standard deviation of the production time series.[24] After saturation the only way to increase the smoothing will be to increase the area—which has a limit somewhere too. To quantify the smoothing effect, first the standard deviation is looked at. For combined time series the variance σ^2 is

$$\sigma^2_{\text{ensemble}} = \frac{1}{N^2}\sum_{x=1}^{N}\sum_{y=1}^{N}\sigma_x\sigma_y r_{x,y} \tag{5}$$

where N is the number of time series forming the ensemble time series, σ is the standard deviation and $r_{x,y}$ is the cross-correlation. Now, if the time series are uncorrelated, $r_{x,y}$ is close to zero and there remains only the variances of the original time series. With a further assumption of being the same for all original time series, σ_{ensemble} is reduced to

$$\sigma^2_{\text{ensemble}} = \frac{1}{N^2}\sum_{x=1}^{N}\sigma_x^2 = \frac{1}{N}\sigma_x^2, \qquad \sigma_{\text{ensemble}} = \frac{1}{\sqrt{N}}\sigma_x \tag{6}$$

If, on the other hand, the time series are perfectly correlated, $r_{x,y}$ is 1 and, again assuming the standard deviations of the original time series equally large, σ_{ensemble} becomes

$$\sigma^2_{\text{ensemble}} = \frac{1}{N^2}\sum_{x=1}^{N}\sum_{y=1}^{N}\sigma_x\sigma_y = \sigma_x^2, \qquad \sigma_{\text{ensemble}} = \sigma_x \tag{7}$$

Now, as we have time series that are correlated, some more and some less, the standard deviation will lie somewhere in the middle of these extremes:[25]

$$\sigma_{\text{ensemble}} = N^{-k}\sigma_x, \quad k = -\frac{1}{2} \quad \text{to} \quad 0 \tag{8}$$

Assuming the number of data sets N is growing with the size of the area and fitting the function in (8) to the Danish data of hourly variations gives $k = -0{\cdot}2437$ and $\sigma_x = 0{\cdot}1275$ (almost 13% of capacity), with a reasonably good fit of the data ($R^2 = 0{\cdot}83$). Giving more weight to the data points with larger N, a curve fit of $y = 0{\cdot}11x^{-0{\cdot}24}$ is used here in Figure 15, this dotted line also follows more the points with lowest standard deviation values, giving an indication of how the reduction is with proper geographical spreading of the turbines in the area.

When looking at the trend of decreasing standard deviation with increasing number of wind farms in a larger area in Figure 15, the conclusion is that the Norwegian and Swedish data sets will exaggerate the hourly variations if upscaled. There will be a slight overestimation of variability for the Finnish data when upscaling the data to large-scale wind power production. Combining the four data sets to form a Nordic data set shows a continuing smoothing effect in Figure 15. It has thus been considered representative for the study of large-scale wind power.

Even for Denmark there can be some caveats as to how well the data represent future wind power production. In the future there will be fewer turbines and sites, but better production from MW-scale high turbines, especially offshore. When a substantial share of wind energy comes from large offshore wind farms, this will

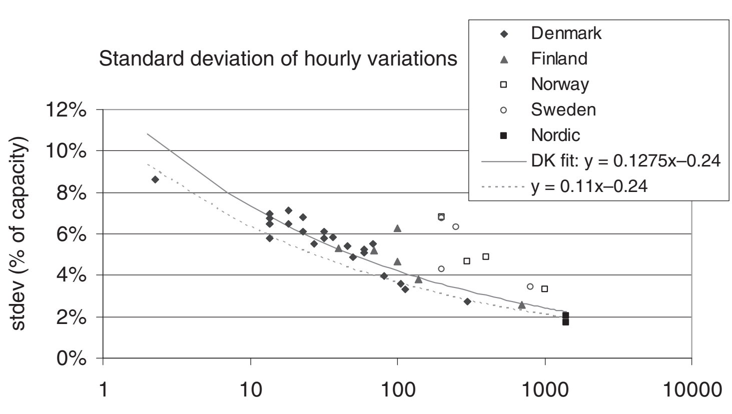

Figure 15. Reduction in variability of wind power production: reduction in standard deviation of hourly variations taken from different areas, year 2001 data. Fit for Danish data gives the full line ($y = 0{\cdot}1275x^{-0{\cdot}24}$). The dotted line follows the least variable time series, showing the effect of good geographical dispersion within the area

have an impact on the production, bringing about a less dispersed and thus more variable production, but also higher duration, as there are fewer calms than onshore.[37]

Summary and Conclusions

Large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output.

In this study the focus is on the hourly time scale impacts on the power system, based on real wind power production data. Example years 2000–2002 were studied. As a total period, 2000–2002 will give a production that is less than average: 90% of the average production in Denmark, 87% in Finland and 96% in Sweden.

Average production in the Nordic countries is highest in Norway, 31%–34% of installed capacity, and about 22%–24% of capacity in the other countries during the example years. The seasonal variation was clearly present in the data sets: more production in winter than in summer. Wind power production in Denmark and Sweden experiences a more pronounced diurnal variation, whereas the sites in the Northern parts of Finland, Sweden and Norway do not experience any detectable diurnal variation.

From the combined production in the Nordic countries it can be seen that, as wind power production comes from geographically distributed wind farms, the total production never reaches the total installed capacity and it is hardly ever totally calm. Production above 50% of rated capacity is rare in summer and production above 75% is rare in winter. The lowest hourly production was 1·2% of capacity. The production was below 5% of capacity about 2% of the time.

Correlation of hourly wind power production is strong (above 0·7) for distances less than 100 km and becomes weaker (below 0·5) for distances above 200–500 km. The large-scale wind power production of the countries is correlated between Denmark and Sweden and weakly correlated between the other countries. No correlation between the hourly variations of wind power production was seen in the data sets for the countries.

The hourly variations of large-scale wind power production are 91%–94% of the time within ±5% of capacity and 99% of the time between ±10% of capacity. For the total Nordic time series the hourly variations are about 98% of the time within ±5% of capacity. Taking only the time periods when the initial production level is more than the average production, the larger variations occur about twice as often (relatively).

To be able to upscale wind power production data to represent large-scale production data, the smoothing effect should be present in the time series. When enough turbines from a large enough area are combined, the smoothing effect reaches saturation and the time series can be upscaled with representative hourly variations.

From the available hourly time series for Denmark, guidelines for the statistical properties of large-scale wind power were made. An hourly time series of large-scale wind power production should have the standard deviation of the hourly production series less than 20% of capacity, the maximum hourly production less than 100% (85%–95% depending on how large the area in question is), the duration of calms limited or non-existent, the standard deviation of the hourly variation series less than 3% of capacity and the hourly variations within ±20% of capacity, or even less if the area is larger than the size of Denmark (300×300 km^2). The clearest indication of reduced variability in the time series was found to be the standard deviation of the hourly variation time series.

According to these criteria, the data set for Finland is quite representative for large-scale wind power production and its hourly variations. The data sets for Norway and Sweden can be used to present wind power production, but for the hourly variations they are not representative. This is mainly revealed by the range and standard deviation of hourly variations of the production time series, which is not as smooth as a large-scale wind power production from thousands of turbines would be. Combining the four data sets to form a Nordic data set shows a continuing smoothing effect, so it has been considered representative for the study of large-scale wind power.

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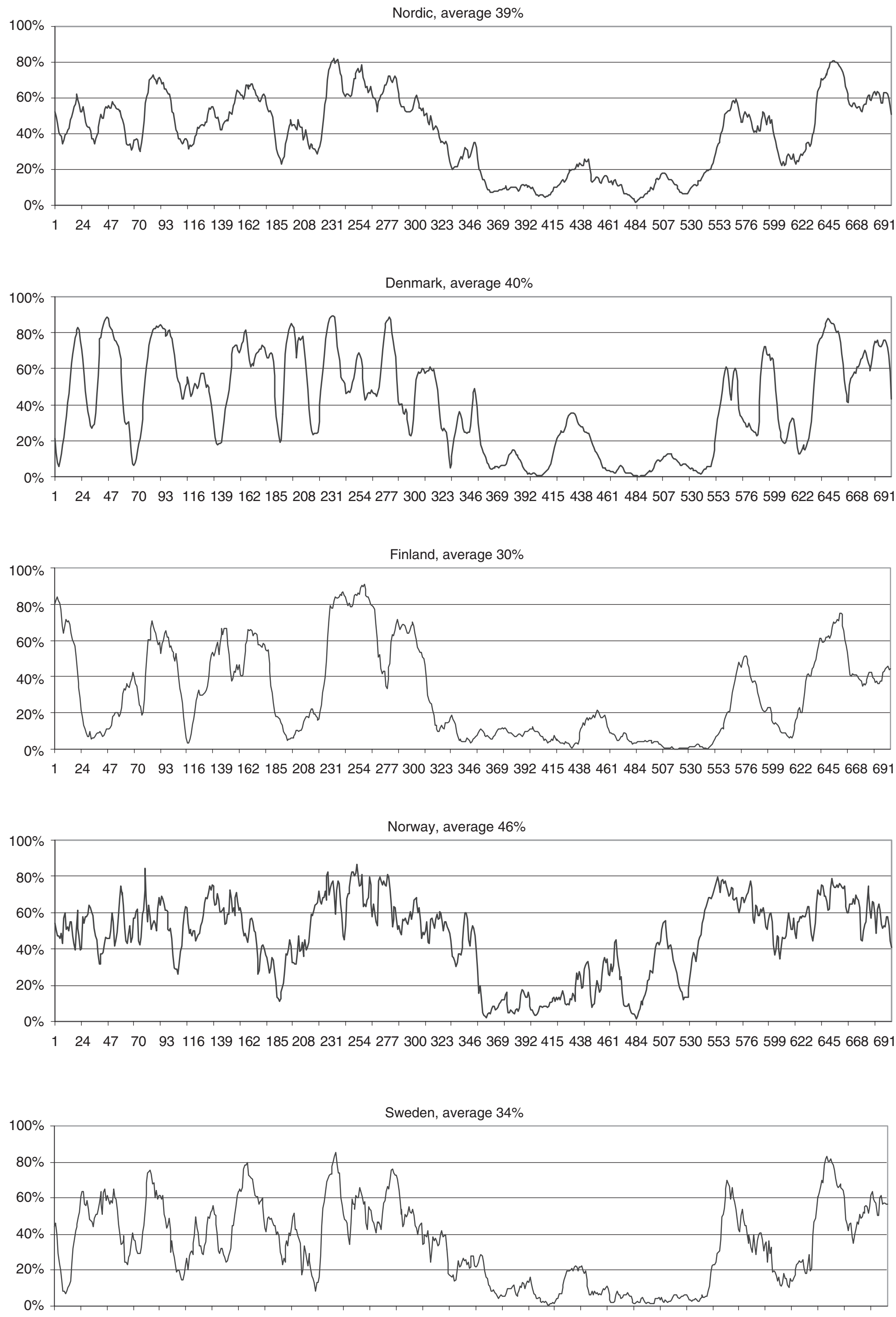

Figure 16. Hourly wind power production in February 2000. The production is given as % of installed capacity (y-axis). The average production during the month is denoted above the curve

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Research Article

Impact of Hourly Wind Power Variations on the System Operation in the Nordic Countries

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Key words: ■■

The variations of wind power production will increase the flexibility needed in the system when significant amounts of load are covered by wind power. When studying the incremental effects that varying wind power production imposes on the power system, it is important to study the system as a whole: only the net imbalances have to be balanced by the system. Large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output. The goal of this work was to estimate the increase in hourly load-following reserve requirements based on real wind power production and synchronous hourly load data in the four Nordic countries. The result is an increasing effect on reserve requirements with increasing wind power penetration. At a 10% penetration level (wind power production of gross demand) this is estimated as 1·5%–4% of installed wind capacity, taking into account that load variations are more predictable than wind power variations. Copyright © 2005 John Wiley & Sons, Ltd.

Introduction

Integration of wind power in large power systems is mainly subject to theoretical studies, as wind power penetration levels are still modest. Even though the penetration in areas such as West Denmark is already high (about 20% of yearly electricity consumption), wind power represents only 1%–2% of the Nordel and Central Europe (UCTE) systems.

Wind power production is characterized by variations on all time scales: seconds, minutes, hours, days, months and years. Even the short-term variations are to some extent unpredictable. The additional requirements and costs of balancing the system on the operational time scale (from several minutes to several hours) are primarily due to the fluctuations in power output generated from wind. To what extent extra costs will occur depends on how large a share is produced by wind power, as well as on the power system in question: the inherent load variations and flexibility of the production capacity mix.

For the power system the relevant wind power production to study is that of larger areas. This means large geographical spreading of installed wind power, which will reduce the variability and increase the predictability of wind power production. Not taking this into account can result in an exaggeration of the impacts of wind power.

Integrating wind power in power systems means taking into account the varying pattern of wind power production in scheduling the generation and reserve units in the power system. Integration costs or system costs are the costs incurred in incorporating the electricity from wind power into a real-time electricity supply, ensuring system security.

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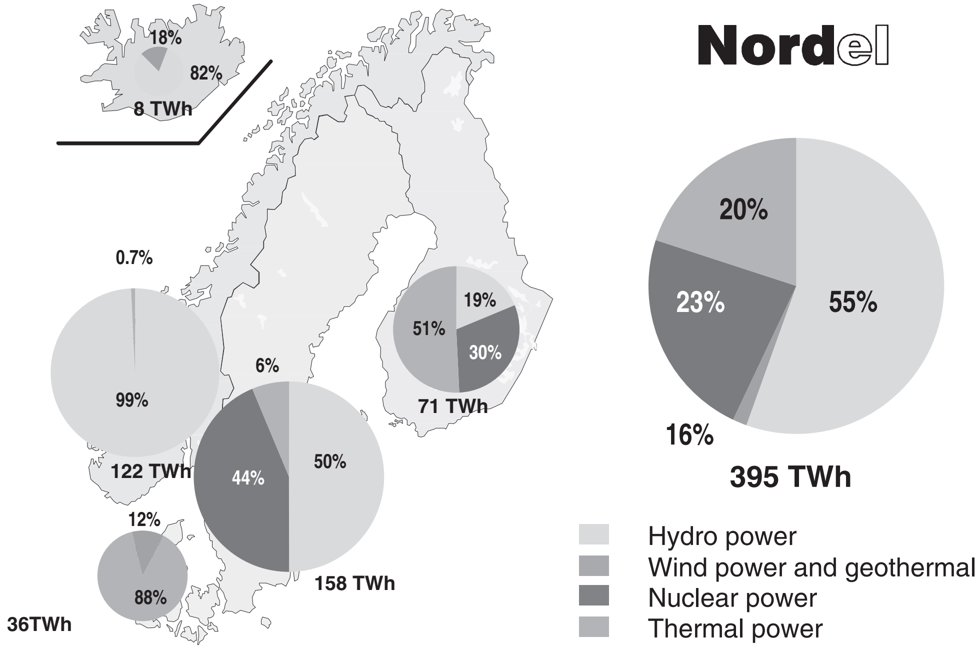


Figure 1. Electricity production in the Nordic countries in 2001[1]

The Area of the Study

The joint, liberalized Nordic electricity market covers Norway, Sweden, Finland and Denmark. East Denmark is part of the Nordel system, while West Denmark is part of the Central Europe UCTE system. They are not connected by a transmission line, but both are connected to Sweden and Germany, and West Denmark is also connected to Norway by a DC link. The production mix is shown in Figure 1.[1] A large share of hydro power is characteristic for the Nordic area: Norway covers almost 100%, Sweden almost 50% and Finland almost 20% of electricity consumption by hydro power.

The installed wind power capacity at the beginning of 2003 was 2200 MW in West Denmark,[2] 573 MW in East Denmark,[3] 345 MW in Sweden,[4] 97 MW in Norway[5] and 41 MW in Finland.[6] In Denmark, system integration of wind power is already a reality, whereas in other countries it is still a subject for discussion. In Denmark the scheduling of production units takes into account wind power production, and prediction methods together with the hourly trade in the spot and regulation markets are used in order to accommodate the substantial share of wind power in the system.[7]

Previous work

Studies of large-scale wind power production, its variability and its effects on energy systems have been carried out to some extent in the 1990s and increasingly in the first years of the new millennium. The first comprehensive article about the system impacts of wind power was by Grubb,[8] considering the UK power system.

First experiences from West Denmark and the Northern coast of Germany have shown that, when significant amounts of electrical demand are covered by wind power, increased flexibility is needed in the system. This is first seen as increased transmission with neighbouring countries.[7,9,10] There is experience from as well as studies on thermal systems that take in wind power production but leave, even in high winds, the thermal plants running at partial load in order to provide regulation power. The results show that about 10% (energy) penetration is the starting point where a curtailing of wind power may become necessary. When wind power production is about 20% of yearly consumption, the amount of discarded energy will become substantial and about 10% of the total wind power produced will be lost.[11,12]

As a conclusion of several studies in the USA[13] it has become clear that, to estimate the impacts of wind power on the power system, the wind-induced imbalances have to be treated together with aggregated system imbalances. Estimating the increased reserve requirements has resulted in a very small impact on the regulation time scale.[14,15] However, on the load-following time scale, increasing penetration of wind power will result in an increasing impact.[16–20] In many cases the studies give conservative estimates because they lack detailed, representative data for both the large scale wind power production and the load from the same area.

The present study is one step towards quantifying the impacts of large-scale wind power on the operation of the power system, based on existing production data on an hourly level. The wind power data used in this article and the smoothing effect of large-scale wind power production are analysed in detail in a previous article from this study.[21]

Power System Operation and Wind Power

Electric power systems include power plants, consumers of electric energy, and transmission and distribution networks connecting the production and consumption sites. The power system, which is operated synchronously, has the same frequency. At nominal frequency (in Europe 50 Hz) the production and consumption (including losses in transmission and distribution) are in balance. When the frequency is below 50 Hz, the consumption of electric energy is higher than the production. If the frequency is above 50 Hz, the consumption of electric energy is lower than the production. This constantly fluctuating interconnected system should maintain the balance so that faults and disturbances are cleared with minimal disadvantage in the delivery of electricity.

Merit order of electricity production

Power systems comprise a wide variety of generating plant types, which have a range of capital and operating costs. The operation of a power system involves providing a total amount of electricity, at each instant, corresponding to a varying load from the electricity consumption. To achieve this cost-effectively, the power plants running at low operational costs will be kept running almost all the time (base load demand), while the power plants with higher costs will be run only when the load is high.

When ignoring second-order costs (e.g. start-up, shutdown, reserves), plants can be stacked in merit order, where production with low marginal costs runs first. Wind power plants (as well as other variable sources such as solar and tidal) have very low marginal costs, usually assumed as zero, so they come to the top of the merit order, i.e. their power is used whenever available.[8]

The electricity markets operate in a similar way, at least theoretically. The price the producers bid to the market is slightly higher than their marginal costs, because it is cost effective for the producers to operate as long as they get a price higher than their marginal costs. When the market is cleared, the power plants operating at lowest bids come first.

Reserves

Failure to keep the electricity system running has serious and costly consequences, so the reliability of the system has to be kept at a very high level. Security of supply needs to be maintained in both the short and the long term. This means maintaining both flexibility and reserves necessary to keep the system operating under a range of conditions, also in peak load situations. These conditions include credible plant outages as well as predictable and uncertain variations in load and in primary generation resources, including wind.

Load following is performed partly beforehand and partly by operational reserves. Beforehand the scheduling and dispatch of power plants is done according to the load forecast. This involves also the start-ups and shutdowns of slower power plants, called unit commitment, on the time scale of 3–12 h. The operational reserves are used to balance the load forecast errors. Figure 2 gives an example of the actual load in the system over 3 h compared with the hourly forecasted load, showing forecast errors and short-term load deviations in the system.

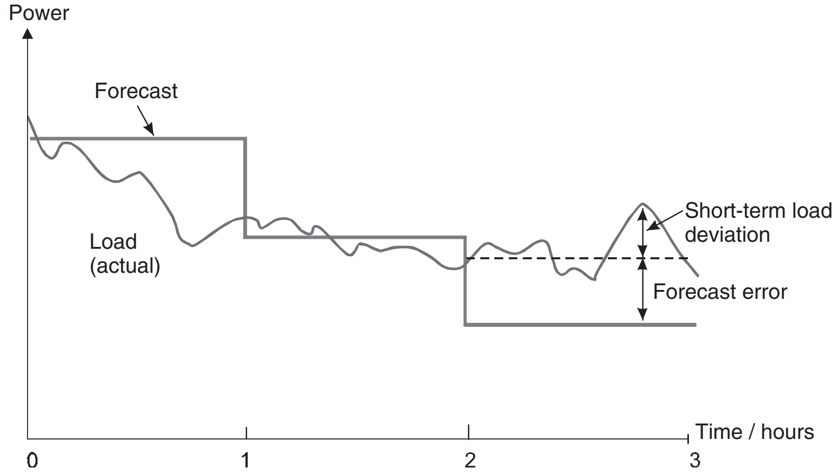


Figure 2. Example of actual load in the system during 3 h compared with forecasted load

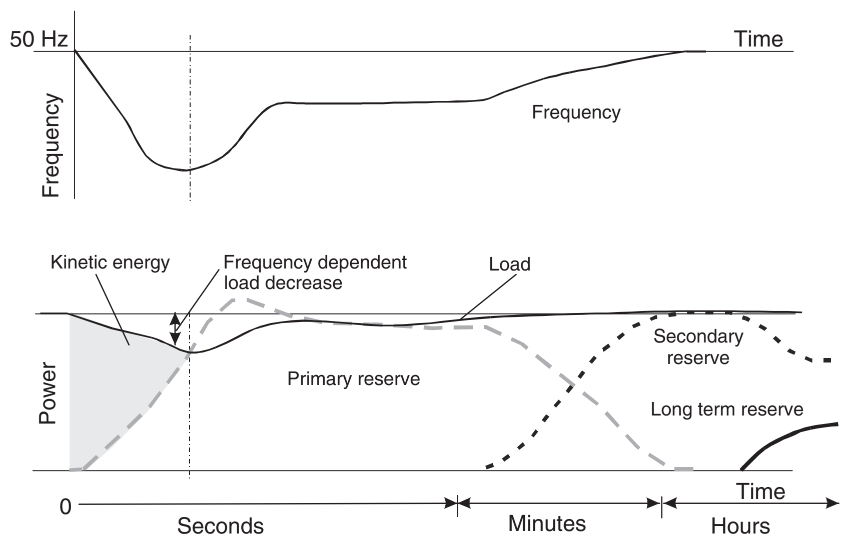


Figure 3. Activation of power reserves and frequency of power system as a function of time when a large power plant is disconnected from the power system[22]

The reserves are divided into different categories according to the time scale within which they operate. An example of how the reserves operate is illustrated in Figure 3.[22] It shows the frequency of the system and activation of reserves as a function of time when a large power plant is disconnected from the power system. Activation of reserves divides the reserves into primary reserve, secondary reserve (also called fast reserve) and long-term reserve (also called slow reserve or tertiary reserve). The primary reserve in power plants is activated automatically by frequency fluctuations. The secondary reserve is activated within 10–15 min of the occurrence of a frequency deviation from nominal frequency. It replaces the primary reserve and will be in operation until itself being replaced by the long-term reserve, as seen from Figure 3. The secondary reserve consists mostly of rapidly starting gas turbine power plants, hydro (pump) storage plants and load shedding.

The operation of the power system has to be guaranteed also in the liberalized electricity markets. In the Nordic electricity market there is an independent Transmission System Operator (TSO) in every country as a system-responsible grid company securing system operation. The scheduling and dispatch of the power plants (unit commitment and load following according to load forecasts) can be dealt with in the Nordpool Elspot market as well as by bilateral contracts between the players. The TSOs take over the regulation of the balance during the hour of operation. First the balance is secured by means of primary reserve (automatic frequency reserve and instantaneous disturbance reserve). In the event of a major frequency deviation the TSOs adjust the production or the consumption manually, using a secondary reserve called regulating power. They do this through a common regulating power market 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 primary and secondary reserves. The primary control of the synchronous part of Nordel is according to the total net balance. The TSOs in Sweden and Norway have agreed to share the responsibility of maintaining the frequency of the whole area during operation (primary reserve for operation). All the TSOs are responsible for activating the secondary reserve of their own areas and for ensuring that the physical constraints of the transmission grid are observed.[23] The balancing management for the liberalized market remains the same in that the TSOs only regulate the net imbalance of the system.

The impacts of wind power on the power system

The system impacts of wind energy are presented schematically in Figure 4. These impacts are divided into two: short term, balancing the system on the operational time scale (minutes to hours), and long term, providing enough power and energy in peak load situations. The additional requirements and costs of balancing the system on the operational time scale (from several minutes to several hours) are primarily driven by fluctuations in wind generation output. Some of the fluctuations are predictable 2–40 h ahead. The varying production pattern of wind power changes the scheduling and unit commitment of the other production plants and the use of transmission between regions—either losses or benefits are introduced to the system—compared with the situation without wind. Some of the fluctuations remain unpredicted or mispredicted and have to be

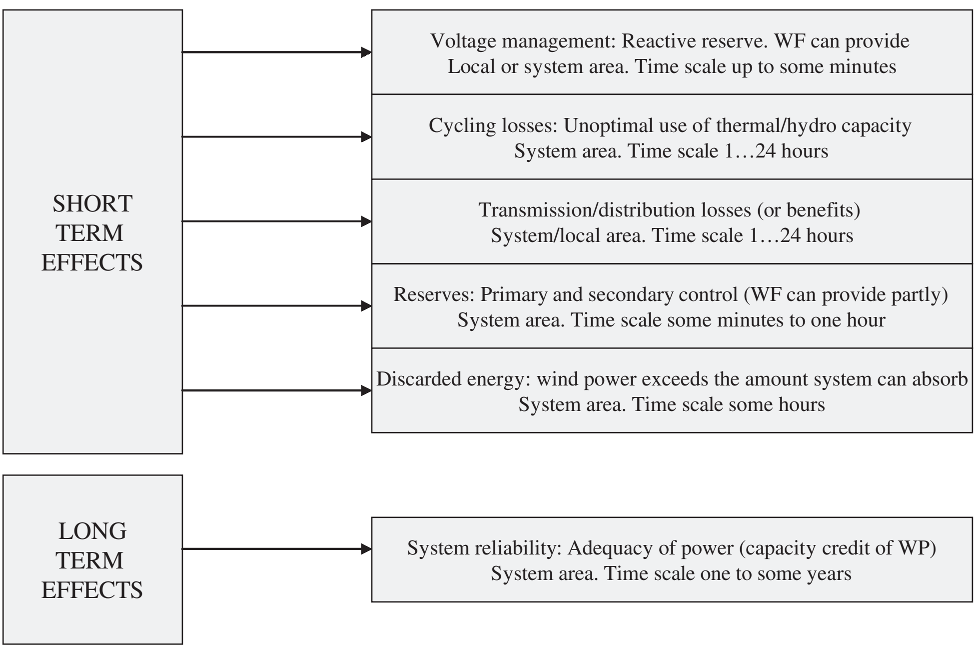


Figure 4. System impacts of wind power (WP) and wind farms (WF) causing integration costs. Part of the impacts can be beneficial for the system, and wind power can have a value, not only costs

Figure 5. Data for hourly wind power production were available from 21 sites in Finland, six sites in Sweden, 6–12 sites in Norway (the lighter-coloured sites only for part of the time) and the aggregated total production of hundreds of sites in West and East Denmark

handled by the regulation market and balancing services (mainly secondary reserves). There are means to reduce the variations 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 magnitude and frequency, over short time scales.[24] This 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 terms of cost-effectiveness.

This study is involved with the short-term effects and, more specifically, the operating reserve requirements of wind power. The relevant system area to look at varies according to the impact studied (Figure 4).[25] For intra-hour variations, frequency control and load following, the synchronously operated system forms a relevant area. DC links connecting synchronously operated areas can also be automated to be used for primary power control; their power reserve capacity is usually, however, only allocated as emergency power supply. When looking at a large interconnected area, it has to be taken into account that benefits exist when there are no bottlenecks of transmission between the areas.[26] The relevant time scale for the operating reserve requirements is from several minutes to several hours. For wind power, also prediction errors 2–36 h ahead can affect the operating reserve. However, this will depend on how the producers or the balance-responsible players act, as they have the possibility to compensate for the prediction errors as the time of delivery approaches. In this study the hourly time series are used owing to a lack of 1 or 10 min data. As the hourly variations are greater than the 15 or 1 min variations, the results drawn will be conservative.

Data Used in This Study

The data-used in this study are the measured output of wind power plants and wind parks (Figure 5). Realized hourly wind power production time series from the four Nordic countries were collected. The total electricity consumption of the countries, also as hourly time series, was obtained to see the effect of wind variations compared with load variations. Data were collected for years 2000–2002.

For the hourly load time series for Finland there were some conspicuous load variations from one hour to the next. To be sure not to overestimate the initial load variations, one peak in 2001 and four peaks in 2002 data were corrected. For the Norway data, 12 conspicuous peaks in spring/summer 2000 load data were corrected as well so as not to be reflected in the total Nordic load data.

The data-handling procedure for wind power time series is described in more detail in Reference 27 and the data series used in Reference 21. A Nordic data set was formed from the data sets of the four countries. The production at each hour was a simple average of the % of capacity production of the four countries. In terms of capacity this would mean setting for example 3000 MW in each country, a total of 12,000 MW. This is somewhat theoretical, as Denmark is now dominating the installed wind power and probably will be for quite some time, even though the wind energy potential is probably as large in all four countries taking into account offshore potential. To see the effect of a more concentrated wind power capacity in the Nordic countries, also a data set called "Nordic 2010" was formed where half of the wind power capacity is in Denmark.

Wind power production varies according to wind resource, the yearly production is typically within ±20% of the long-term average production. The representativeness of the wind data has been looked at in Reference 21. As a total period, 2000–2002 will give a production that is less than average compared with wind power production indices available for the Nordic countries: 90% of average production in Denmark, 87% in Finland and 96% in Sweden. Year 2000 was close to average and year 2001 was clearly less windy than average. Year 2002 was close to average in Denmark and Sweden and a very-low-wind year in Finland. In addition to the representativeness of the study period, it is important to look at the representativeness of the data to describe the hourly variations of large-scale wind power production. The data need to be upscaled to look for the future impacts of large-scale wind power. If too few time series 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 and adding more turbines/sites will not result in less variability. These data were deemed sufficient for Denmark, Finland and the total Nordic time series, but unsatisfactory for upscaling the time series of Sweden and Norway.[21]

Wind Power Production and Load

In this section the basic patterns of electrical load together with wind power production are presented. The main focus is on the hourly variations and on peak load situations.

Wind power is a production form that partly resembles electric consumption, the load. It varies each moment, with part of it being unpredictable, causing unexpected variations in the system. As an example, the wind power production in January 2000 is presented together with the load in Figure 6. The wind power production is here upscaled for Finland to represent approximately the same wind power penetration level* as in Denmark (roughly 10% of gross demand).

Basic statistics of the hourly load and wind power time series

Time series of load in the Nordic countries, featuring also duration curves, are presented in Figure 7 for year 2001. Electric load is characterized by a daily pattern, higher on weekdays than at weekends.[28] In addition to

*Wind power penetration is the share of produced wind power in the power system, presented here as % of energy, yearly gross demand. Penetration as % of installed capacity is also used in some studies, which is a considerably larger figure than expressing it as % of energy owing to the low capacity value of wind power.

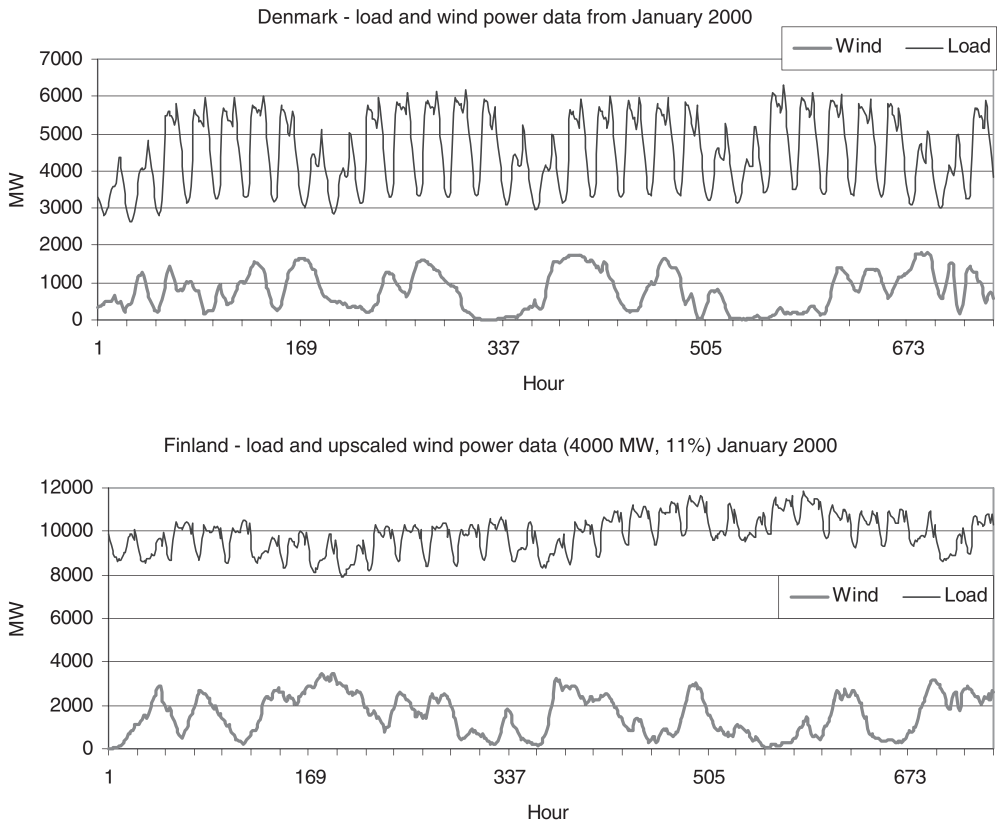


Figure 6. Electricity consumption (load) and wind power production in January 2000. Denmark is real data (12% wind power). For Finland, data from wind parks are scaled up to wind power penetration of about 11% of gross demand

daily cycles, temperature effects can be seen in the graphs: the load is generally lower during summer, and different weeks in winter show a dependence on temperature. As the *y*-axis scale is relative to the peak load, it can be seen that the load varies relatively more in Denmark compared with the other three countries with energy-intensive industry. Also electric heating used in Sweden and Norway and to a lesser extent in Finland can explain part of the difference.

Basic statistics of the load time series are presented in Table I for years 2000–2002. In both Sweden and Norway the consumption is larger than in Finland and Denmark together. Denmark has by far the lowest consumption, only about 10% of the total Nordic demand. The total yearly electric consumption in the Nordic countries has been rising by 2% between 2000 and 2001 and stayed about the same in 2002. In Finland the increase has been highest and continued from 2001 to 2002. In Denmark the consumption is quite stable.

The maximum peak load was in 2001, except for Finland in 2002. The peak load is about three times larger than the minimum load. Some smoothing can be seen in the total Nordic load time series: the peak is lower and the minimum load higher than the sum of the countries, as the peaks do not coincide. The Finnish load series is considerably less variable than for the other countries, as can be seen from the standard deviation relative to the mean value.

An example of year 2001 data for wind power production is presented in Figure 8. The basic statistics of wind data for years 2000–2002 are given in Table II. When wind power production comes from geographically distributed wind farms, the total production never reaches the total installed capacity and it is hardly ever totally calm. From the combined production in the Nordic countries, production above 50% of rated capacity

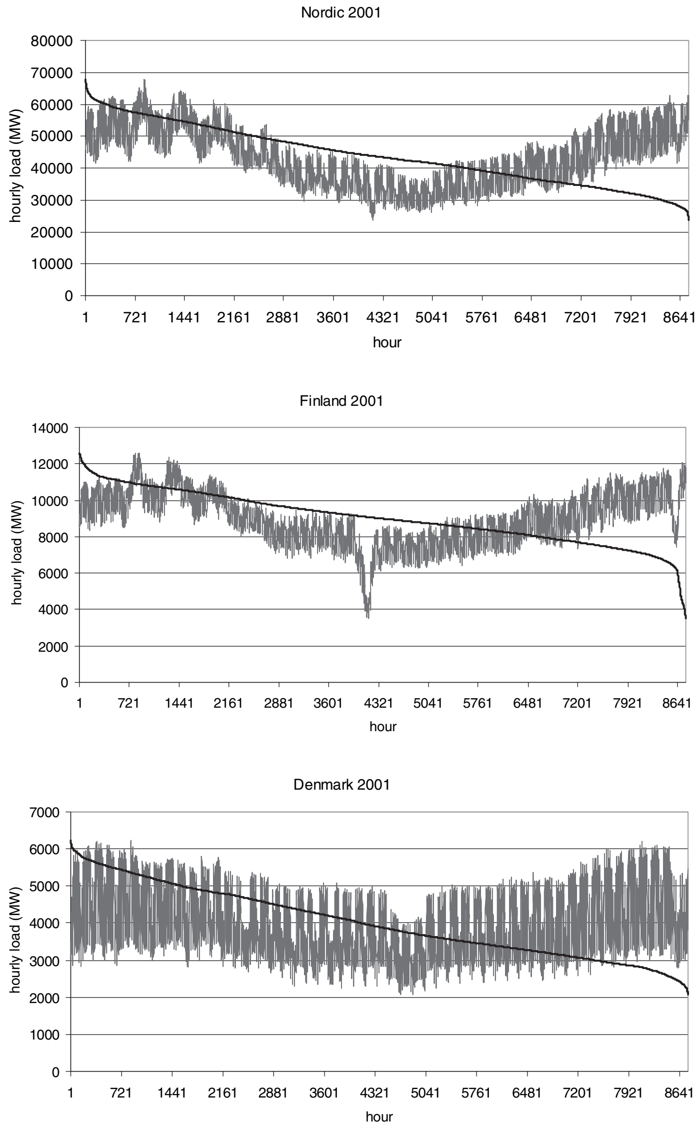


Figure 7. Hourly load of Finland, Denmark and the total of Nordic countries, chronologically and as duration curve. The y-scale is different for each graph

is rare in summer and production above 75% is rare in winter. The lowest hourly production was 1·2% of capacity for the Nordic wind power production time series.[21]

Correlation of load, wind power and other variable energy sources

The correlation between production and electrical load is of importance when considering the power system effects of a variable production form such as wind power. If wind power production has a tendency of following the load, e.g. wind power production increasing in the morning and decreasing in the evening, this has a beneficial effect.

For the Nordic data there is a slight positive correlation between wind power production and load, which means that somewhat more often the wind power production increases when the load increases, and *vice versa*,

Table I. Key figures for electric load in the study period 2000–2002.[a] The values are in MW and in % of peak load and the statistical parameters are presented here as averages of the values calculated separately for the three years (except for the maximum peak)

Statistic	Denmark	Finland	Norway	Sweden	Nordic
Sum (TWh a^{-1})	35/35/35	76/79/83	120/123/118	141/147/149	372/385/385
Max peak (MW)	6,284	13,654	23,054	26,323	67,854
Min (MW/%)	2,020/32	3,600/28	7,410/35	9,100/35	24,130/37
Peak/min[b]	3·09	3·52	2·89	2·84	2·69
Average (MW/%)	3,990/64	9,050/71	13,750/64	16,620/64	43,410/67
Stdev (MW/%)	930/15	1,380/11	3,030/14	3,580/14	8,530/13
Stdev/average (%)	23	15	22	22	20

[a] The total electrical consumption in the hourly time series is not exactly measured. This is why the electricity statistics show slightly different values:[1] the total consumption in the countries was 1%–4% higher in 2000, 1%–3% in 2001 and 1%–2% in 2002 (for example, the consumption for year 2001 was 35·4 for Denmark, 81·2 for Finland, 125·5 for Norway and 150·5 for Sweden, a total of 392·5 TWh).
[b] Peak/min is the reciprocal of min as % of peak load in the row above.

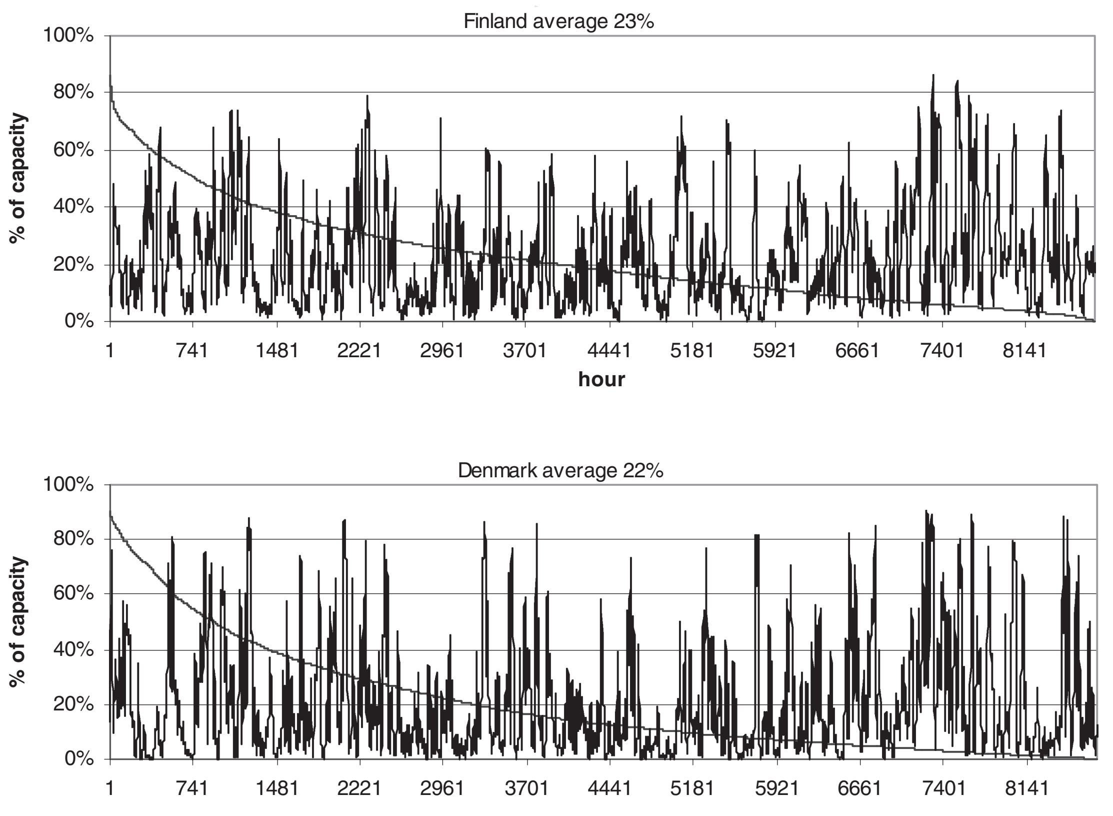


Figure 8. Hourly wind power production as % of capacity in Denmark and Finland in 2001, chronologically and as duration curve

Table II. Key figures for wind power production data in years 2000–2002. The values are relative to installed capacity. The width of the areas is presented as largest distance North–South (NS) and West–East (WE)

Statistic	Denmark	Finland	Norway	Sweden	Nordic
Largest distance NS/WE (km)	300/300	1000/400	1400/700	1300/400	1700/1100
Average (%)	24/20/22	24/22/20	34/31/32	24/23/24	27/24/25
Standard Deviation (%)	21·2	17·6	19·6	18·3	14·5
Minimum (%)	0·0	0·0	0·0	0·0	1·2
Maximum (%)	92·7	91·1	93·1	95·0	86·5
Correlation with load	0·21	0·16	0·37	0·24	0·31

than the opposite (Table II). However, when looking at the winter months only, the correlation is near zero. Thus the positive correlation probably comes from the diurnal pattern of wind power, mostly present in the summer.

Even simple statistical independence makes different variable sources more valuable than just more of the same. When variable sources are directly complementary (wind and solar in the same location), there are potentially large benefits. Also, combining variable sources with energy-limited plants can be beneficial. An example of an energy-limited production form is hydro power, where the maximum power cannot be produced during all hours of the year as there is not enough water to run through. Hydro inflow has a peak in May/June in the Nordic countries, whereas wind power production is dominant in the winter (October–February). Studies in Sweden and Norway show that wind power production combined with hydro power brings benefits for the system.[29,30]

Wind affects the heat demand. In the case of electric heating, this might have a positive impact through electric demand. In these data this effect was not seen, as the correlation between load and wind power production was close to zero in the winter also for Norway and Sweden, where electric heating is used. In the case of producing heat by district heating with combined heat and power (CHP) plants, this can be a negative impact, both wind power and CHP producing peaks at the same time.[7] The correlation of wind power production and district heating CHP production is only slightly positive for Denmark (0·14–0·24) and Finland (0·17–0·27). In the winter, again, the correlation is nearly zero.

Hourly variations of load and wind power production

The hourly load variation is here defined as the difference in load between two consecutive hours:

$$\Delta L_i = L_i - L_{i-1} \tag{1}$$

For wind power the nominal power (installed capacity) is here chosen as a relative measure:

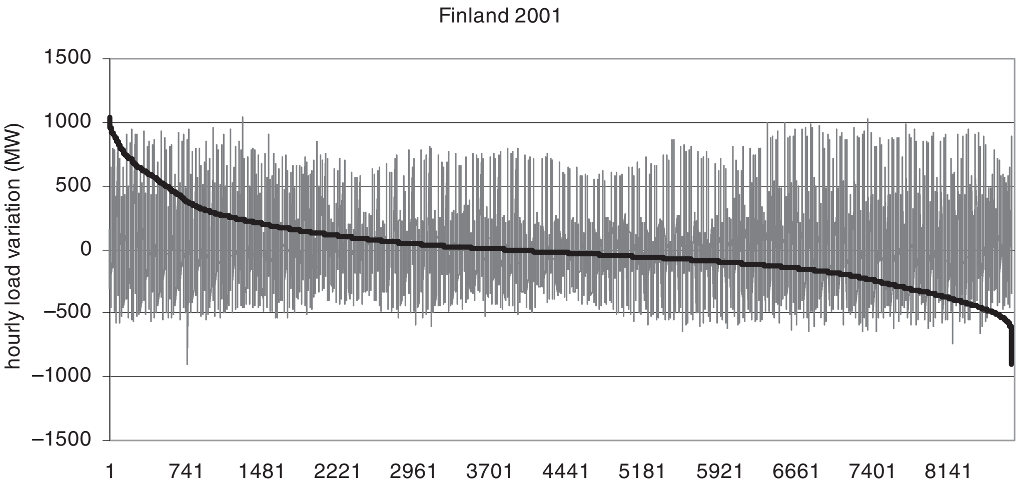
$$p_i = \frac{P_i}{P_{\mathrm{TOT}}} \tag{2}$$

where p_i is the relative wind production for hour i as % of capacity, P_i is the wind power production MWh h^{-1} for hour i and P_{TOT} is the installed capacity. Thus the hourly variation of wind power production can be written as:

$$\Delta p_i = p_i - p_{i-1}, \qquad \Delta P_i = P_i - P_{i-1} \tag{3}$$

An example of the hourly variations of load and wind power is presented in Figures 9 and 10 for Finland and Denmark in year 2001. Large upward variations of load are more frequent than large downward variations. The up-variations are also more costly to the system.

Basic statistics of hourly variations are shown in Table III for load and wind power production.



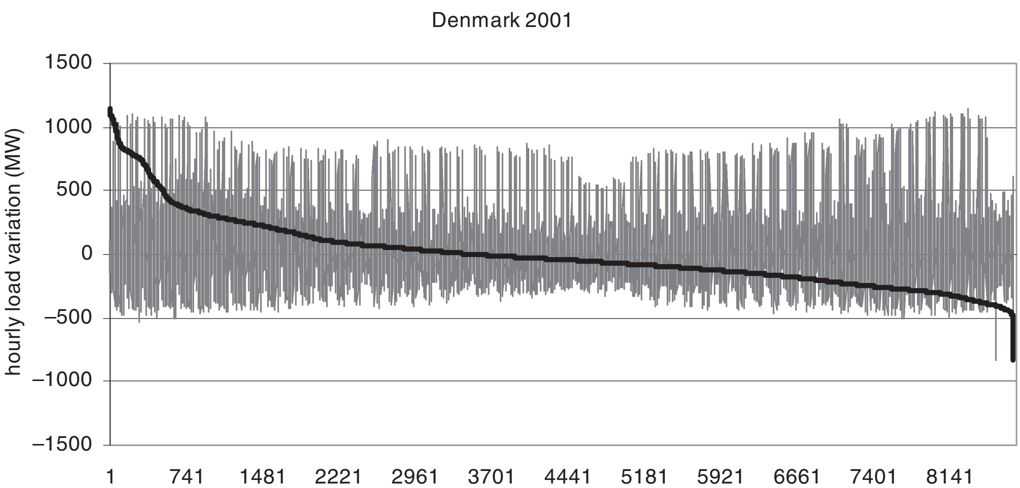


Figure 9. Hourly load variations, example Finland and Denmark, 2001, chronological time series and duration curve

The range of hourly variations of load is ±10% of peak load for the total Nordic load and for Finland; for Denmark it is higher, −14% to 18% of peak load. The hourly load variations are 99% of the time between −450 and 1000 MW in Denmark, −600 and 900 MW in Finland and −3000 and 5000 MW in the total Nordic time series. The typical range of daily cycle can be estimated from Figure 7. It is 16,000 MW for the total Nordic load, nearly 2500 MW for Denmark and 2000 MW for Finland. For Norway it is 2000 MW in summer and 4000 MW in winter, and for Sweden 4000 MW in summer and 6000 MW in winter.

The hourly variations of large-scale wind power production are within −23% to 20% of capacity for Denmark and well within ±20% of capacity for the larger countries. For the total Nordic time series the variations are within −12% to 11% of capacity. For a single country the wind power variations are 90% of the time within ±5% of capacity and 99% of the time within ±10% of capacity. For the total Nordic time series the hourly variations are about 98% of the time within ±5% of capacity.[21] The range of 4 h variations is about ±30% of capacity in the total Nordic time series and −62% to 53% of capacity in Denmark. The range of 12 h variations is about ±50% of capacity in the total Nordic time series and ±80% of capacity in Denmark.

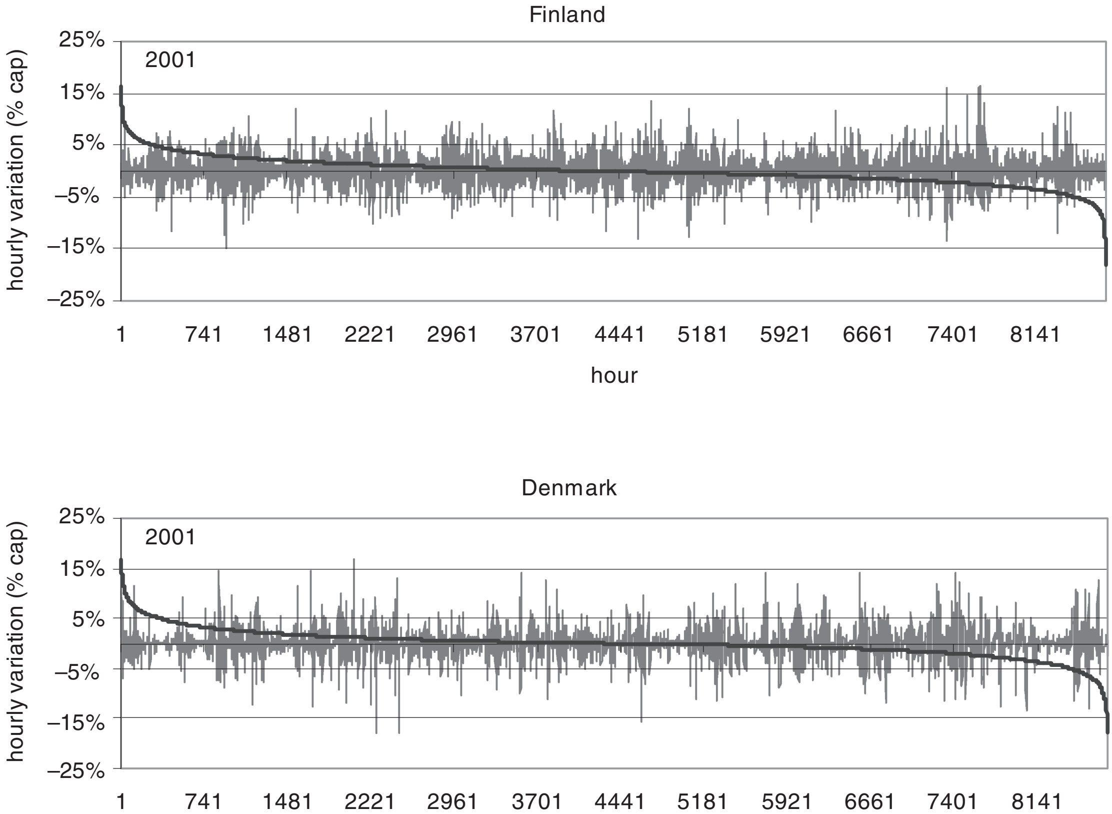


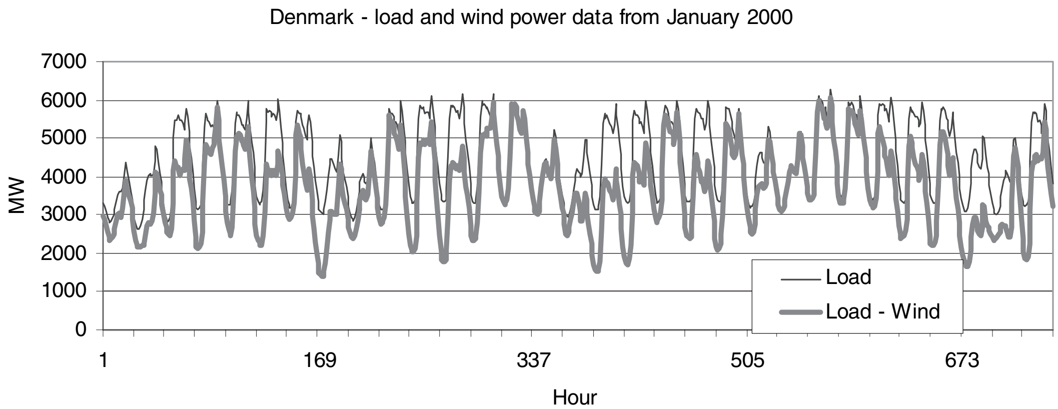
Figure 10. Hourly wind power variations, example Finland and Denmark, 2001, chronological time series and duration curve. Wind power production is relative to installed capacity

Table III. Hourly variations of load and wind power production in the Nordic countries in 2000–2002. The standard deviation of wind power production in MW is at 10% penetration level (of gross demand)

Statistic	Finland	Denmark	Nordic
Load: max up-variation (% of peak)	8·4	18·1	9·9
Load: max down-variation (% of peak)	–7·2	–13·7	–7·6
Load: standard deviation of variations (MW)	268	273	1438
Load: standard deviation of variations (% of peak)	2·0	4·3	2·1
Wind: max up-variation (% of P_{nom})	16·2	20·1	11·7
Wind: max down-variation (% of P_{nom})	–15·7	–23·1	–10·7
Wind: standard deviation of variations (MW)	104	58	336
Wind: standard deviation of variations (% of P_{nom})	2·6	2·9	1·8

Increase in Net Load Variations by Wind Power

To estimate the impact of wind power on power system operational reserves, it has to be studied on a control 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. It is the total system aggregation that has to be balanced. The need for more flexibility in order to meet larger fluctuations in the system depends on how much wind power there is in the system, i.e. what proportion of consumption is covered by wind power production. Also systems are different: the amount of load variations and the flexibility in the system differ from country to country.



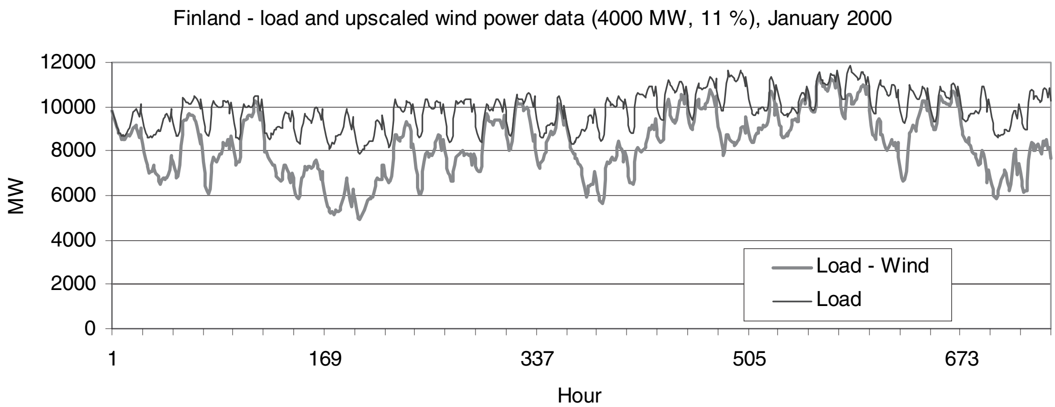


Figure 11. Electricity consumption (load) and net load (wind production subtracted from load) for 2000 MW wind power in Denmark and 4000 MW wind power in Finland

In Figure 11 the same time series as in Figure 6 are shown for January 2000, but the wind power production is subtracted from the load to show the effect of wind on the variations that the system will see. As the load in Finland varies considerably less than that in Denmark, a 10% penetration of wind would result in larger changes in the system in Finland than in Denmark. As the scale in Figure 11 is 1 month, 740 h, mainly the longer term variations (12–48 h) and the changes in those can be seen. On longer time scales there is time for the system to react to these changes—it is the time scale of electricity markets. It is clear from Figure 11 that, to accommodate larger shares of wind power, good prediction models for wind power production are needed.

The short-term variations were studied by hourly time series. Large-scale wind power production varies less the smaller the time step considered.[14] Therefore hourly variations can be used as an estimate for 10–15 min variations. The effect of large-scale wind power on primary reserve on a second to minute time scale has been estimated to be very small.[14]

The net load hourly variations are calculated like the hourly variations in equation (1), but now for the net load time series, where the wind power production is subtracted from the load:

$$\Delta NL_i = NL_i - NL_{i-1} = (L_i - P_i) - (L_{i-1} - P_{i-1}) = \Delta L_i - \Delta P_i \tag{4}$$

where NL denotes the net load (MW), L the load (MW) and P the wind power production and i is the hour (from 2 to 8760 in 2001 and from 2 to 8784 in 2000).

In Figure 12 the amount of hourly variations that the system sees is depicted, without wind (the hourly variations of the net load) and with wind (the hourly variations of net load). The difference in the maximum values

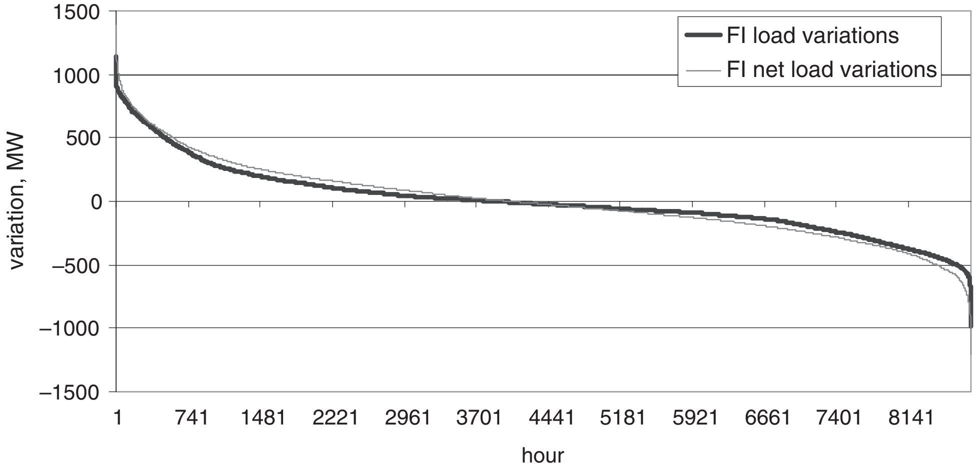


Figure 12. Duration curve of load variations (without wind power) and net load variations (load minus wind power), example Finland, year 2000, 6000 MW wind power (17% of gross demand)

indicates the amount that the operating reserve capacity has to be increased. The difference in the duration curves indicates the amount that the existing reserve capacity is operating more 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 basically be symmetrical. Either up- or down-variations can determine the need for increase in the reserves. In many systems, e.g. Nordel, it is the up-regulation that is more critical to handle by the system.

The increase in hourly variations due to wind power is estimated below in three ways. This increase in hourly variations can be taken as an estimate for increase in the requirement for load-following or secondary reserve in the system. The results are summarized later in Table IV.

Wind power increasing the largest hourly variation in the system

Wind power has an effect on the total amount of load-following reserve capacity if the maximum of net load variations is larger than the maximum of load variations. The largest difference in hourly variations was looked for. This is the maximum increase in variations that the system will see.

The results for years 2000 and 2001 for Finland and Denmark are presented in Figure 13 for both the maximum upward variation (increase in down-regulation) and maximum downward variation (increase in up-regulation). Upscaling the wind power production and looking for the increase in maximum hourly variation in the net load time series, the curves are sometimes increasing linearly and sometimes piecewise linearly depending on what the wind power variation was in relation to the critical few hours of largest load variations. It can be seen from Figure 13 that this kind of analysis is very sensitive to the hourly data in question and can give very different results for different years. The increase in variations can be 0%–4% of installed capacity at 5% penetration, 0%–5·5% at 10% penetration and 2%–7% at 15% penetration.

Looking at a single maximum hourly variation per year when determining the increase in the variations due to wind can overestimate the effect, especially if there is any doubt on the reliability of the data. The largest hourly variations of load can be due to erroneous data. Some conspicuous peaks were removed from the Finnish load time series, however, some downward excursions that were not as clearly faulty data are still present in the data, as can be seen in Figure 9. More reliable data would be needed to avoid over- or underestimating the load variations. Variational analysis could be applied, e.g. as in Reference 12, but this might not be enough if there are erroneous peaks in the data. Another approach is presented in the next subsection.

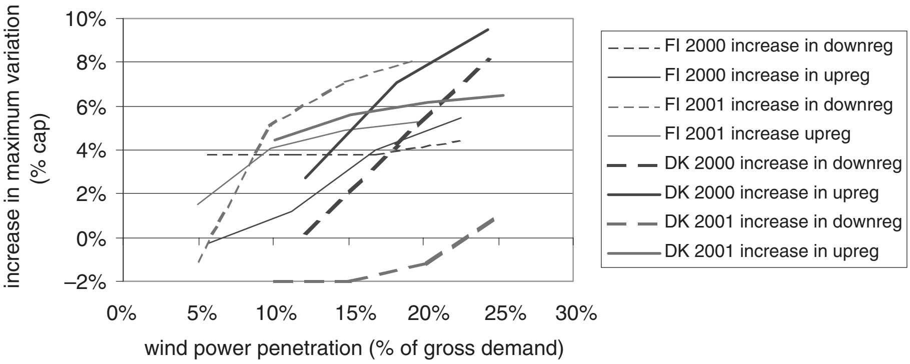


Figure 13. Maximum hourly variation of net load time series compared with load time series gives the increase in variations seen by the power system (as % of installed wind power capacity). Example from upscaling wind power production data for Denmark and Finland

Wind power increasing the hourly variations in the system

Planning and operating a power system is based on probabilities and risk. Reserves in the power system are determined so that variations within a certain probability are covered, e.g. 99·99% of the variations.

The standard deviation σ tells us about the variability of the hourly time series; it is the average deviation from the mean value μ:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n}} \qquad (5)$$

For a normally distributed probability distribution the standard deviation σ is a measure indicating that about 68% of the data are within $\pm\sigma$ of the mean value. Taking a range of $\pm 3\sigma$ will cover 99%, and $\pm 4\sigma$ will cover 99·99% of all variations. For hourly variations the mean value is zero.

From Table III, the standard deviation of the hourly variations can be seen for load and wind power production. As the variations of load and wind power production can be assumed 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:

$$\sigma_{NL} = \sqrt{\sigma_L^2 + \sigma_W^2} \qquad (6)$$

Finally, the increase in the variations can be formulated as the increase in 4σ variations (Figure 14):

$$I = 4(\sigma_{NL} - \sigma_L) \qquad (7)$$

Calculating in this way, we are assuming that wind power only contributes to the reserve requirement by the increase due to its addition to the system. This means that wind power gets the benefit of the existing power system. In the USA, different allocation methods have been elaborated,[31] where the benefit of joining two varying elements is divided by two; in this case the system would benefit a part of the addition of wind power. This would demand more from wind power than the simple increase in variations calculated here by equation (7). Both methods are numerically correct, it is a question of fairness or design of regulation payments. In the Nordic countries, different loads and production units do not pay different tariffs for the regulation burden they

*The hourly variations of wind power production and load are not correlated in these data. However, the distribution of the variation is not normal in the strict sense. This is why the use of equation (6) was checked for these data, and it produced accurate results for the standard deviation of the net load.

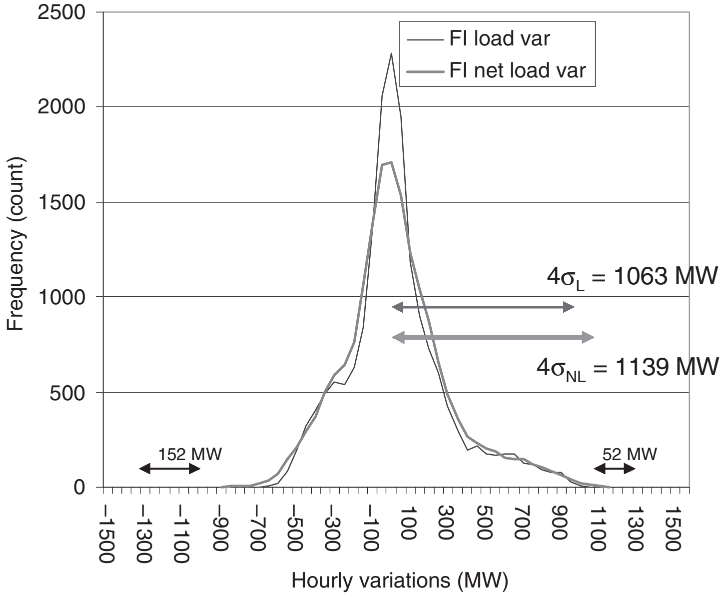


Figure 14. An example of estimating the increase in hourly variations seen by the system for Finnish 2000–2001 data. If only maximum variation is looked at, the increase is determined at the tails of the distribution (52 MW increase in up-variation and 152 MW increase in down-variation). Looking at the standard deviation of the distributions, there is a difference of 76 MW in the 4σ coverage of the variations

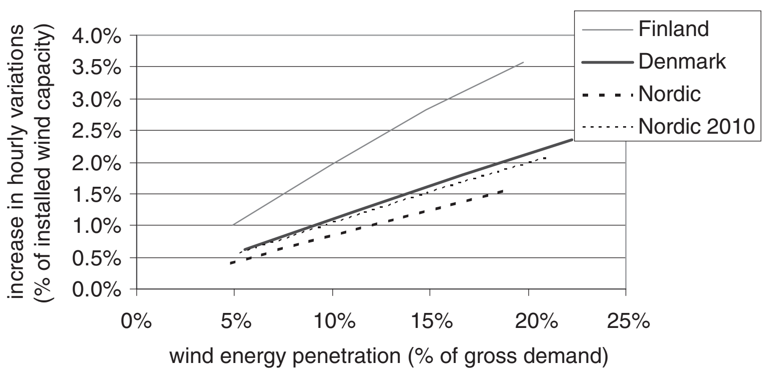


Figure 15. Increase in hourly load-following requirement for wind power, calculated from the standard deviation values of load and wind power production from years 2000–2002. Increase is relative to installed wind power capacity

pose to the system. Until the reserve requirements are allocated to loads and production units, it is well justified to calculate only the simple addition to reserve requirements for wind power.

The probabilistic approach gives lower requirements than only looking at the maximum changes. The increase in variations is 0·5%–1% of installed wind power capacity at 5% penetration (of gross demand), 1%–2% at 10% penetration and 1·8%–2·8% at 15% penetration (Figure 15). More specifically, 2000 MW in Denmark increases the variations by 1% (20 MW), and the same penetration level for Finland, 4000 MW, increases the variations by 2% (80 MW). The reason why the effect of wind power on variations is smaller in Denmark than in Finland is mainly based on the relatively larger load variations in Denmark, absorbing wind variations. Part of the difference may come from overestimated hourly variations of wind power data used here for Finland, due to the non-representative low number of wind power time series.

The same analysis was also made on the combined time series representing the Nordic wind power production. If the Nordic market area was working without bottlenecks of transmission, also the short-term variations of wind power could be absorbed by the system. If the total wind power production was distributed evenly to the four countries, this would result in increased hourly variations in the system, compared with the load variations today, of less than 1% of installed wind power capacity at 10% wind penetration (of gross demand). In other words, 19,000 MW of wind power in the Nordic countries would increase the hourly load-following requirements by about 160 MW. A more concentrated wind power capacity in the Nordic countries, with half of the capacity in Denmark and only 5% in Finland, would result in increased hourly variations in the system of slightly more than 1% of installed capacity at 10% wind penetration (of gross demand).

The total time period analysed here, years 2000–2002, had less than average wind resource. As the wind variability is stronger when the winds are stronger,[27] this might imply that the results presented above are underestimating the impact of wind power production. To check on this, the same analysis was made for the individual years 2000, 2001 and 2002. The variability of wind was slightly larger in 2000 than in the other years for Denmark. For Finland and the total Nordic time series the variability was largest in 2002, probably owing to some wind power time series missing that year. However, the differences in the analyses for the increased variability were not significant. The 4000 MW in Finland would produce 9%–11% of yearly gross demand in 2000–2002 and increase the variations by 76–80 MW (1·9%–2·0%). The 2000 MW in Denmark would produce 10%–12% of gross demand and increase the variations by 22–26 MW (1·1%–1·3%). The 19,000 MW in the Nordic countries would produce 10%–12% of gross demand and increase the variations by 139–166 MW (0·7%–0·9%) or, with a more concentrated wind power capacity, 187–220 MW (1·0%–1·2%).*

The impact of different wind resource years can be looked for from the Danish data. The result for the close to average wind years (2000 and 2002, 95% of average production) is 25 and 26 MW, compared with 24 MW using the three years 2000–2002 (90% of average production). This is a 4%–6% increase in the results, correcting the data of less than average wind resource to represent an average wind year. If only the low-wind year was used (80% of average), this would need to be corrected by 15% (from 22 to 26 MW).

These results suggest that one year of data may be enough to give an estimate in studies of variability of the system if some correction is applied in the case of low-wind years.

Wind power increasing the unexpected hourly variations of load

The analysis in the previous subsection 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.[19]

For wind power the production an hour ahead can be reasonably well forecasted by persistence, i.e. taking the production level at hour $i - 1$ for the predicted value at hour i. Actually this results in using the hourly variation as used in previous subsections as a measure of forecast error of wind power production. The short-term prediction tools can improve on this to some extent, taking into account the forecasted trend of wind speeds in the area, as well as time series techniques that have proven to work quite well for some hours ahead.[32] The persistence is therefore a conservative estimate for the wind power production an hour ahead.

The load prediction has been studied for decades, it is well known and the predictions are quite accurate (within 1%–2% of peak demand). There is a diurnal pattern and dependence of temperature in the demand for electricity. A case study for Finnish 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.[33,34] The mean absolute error, hour ahead, was 0·7% of peak load. This is probably lower than what is experienced in different system areas on average.[19] The forecast error for the load was then compared with wind power variations. The standard deviation of forecast error was 123 MW (1% of peak load), in com-

* Penetration level of wind power is here varying with varying wind resource of the years. It is on average slightly above 10%, to compensate for the total consumption of the hourly time series being 1%–4% lower than the realized load.

Table IV. Summary of results for the increase in hourly variations by wind power in Finland. For maximum hourly variation: if positive, the value is increasing from last hour to current hour. Year 2001 data

Wind power (MW)	2000	4000	6000
Wind power penetration (% of gross demand)	4·9	9·8	14·6
Maximum hourly variation of wind (MW)	280/–310	560/–620	840/–930
Maximum hourly variation of load (MW)	1144/–985	1144/–985	1144/–985
Maximum hourly variation of net load (MW)	1138/–1061	1191/–1137	1385/–1214
Increase in maximum hourly variation (MW)	–6/76	47/152	241/229
Stdev wind power hourly variations (MW)	52	103	155
Stdev load hourly variations (MW)	269	269	269
Stdev net load hourly variations (MW)	274	288	310
Increase in variations, 4σ (MW)	20	76	165
Stdev load forecast error (MW)	123	123	123
Increase in forecast error variations, load forecast only, 4σ (MW)	41	150	298
Stdev wind forecast error (MW)	41	82	124
Increase in forecast error variations, 4σ (MW)	27	100	206

parison with 267 MW for the load hourly variations, so this method assumes that about half of the variability in load can be predicted.

Now, making the same analysis as in the previous subsection but using load forecast error instead of the hourly variation of load, we get the results in Table IV for different wind power prediction error levels.

The results in Table IV show that the results in the previous subsection, based on the simple hourly variations from load and wind power time series, should be increased by 50%–100% depending on the level of wind power forecast (no forecast to hour ahead . . . forecast improving by 20% over persistence). This means that, when producing 10% of yearly electricity consumption with wind power, the increase in hourly load-following requirement would be 1·5%–4% of the installed wind power, instead of 1%–2% as in the previous subsection. More specifically, for Denmark the 2000 MW of wind power would increase the load-following requirement by 30–40 MW, for Finland the 4000 MW by 120–160 MW and for the Nordic countries the 19,000 MW by 240–320 MW.

Summary and Conclusions

In this study the focus is on the hourly time scale impacts on the power system, based on real and synchronous load and wind power production data. The incremental changes to the system due to wind power were studied. The area of study was one country (Finland, Denmark) or the whole Nordic area.

Example years 2000–2002 were studied. As a total period, 2000–2002 will give a wind power production that is less than average: 90% of the average production in Denmark, 87% in Finland and 96% in Sweden.

Electrical load is characterized by a daily pattern, higher on weekdays than at weekends. In addition to daily cycles, strong temperature dependence can be seen in the Nordic countries. Wind power has a slightly positive correlation with the load, especially in Denmark. However, during the winter months the correlation is practically non-existent.

The range of hourly variations of load is ±10% of peak load for the total Nordic load and for Finland; for Denmark it is higher, –14% to 18% of peak load. The hourly load variations are 99% of the time between –450 and 1000 MW in Denmark, –600 and 900 MW in Finland and –3000 and 5000 MW in the total Nordic time series. The hourly variations of large-scale wind power production are within –23% to 20% of capacity for Denmark and well within ±20% of capacity for the larger countries. For the total Nordic time series the variations are within –12% to 11% of capacity. The hourly variations of large-scale wind power production are 99% of the time within ±10% of capacity. For the total Nordic time series the hourly variations are about 98% of the time within ±5% of capacity.

The need for more flexibility in the electricity system, due to short-term variations of wind power, was estimated for Denmark, Finland and the combined Nordic countries. Net load variations (load minus wind production) compared with load variations give an estimate for the needs of the system to react to large-scale wind power. An analysis based on only the maximum hourly variation was found to be very sensitive to the hourly data in question, giving different results for different years of data, depending on what the wind power change was during the critical hours of maximum load changes. A probabilistic approach gave estimates for the range of variations, from the standard deviation (σ) values, taking $\pm 4\sigma$ as the range that covers most variations (99·99% of all variations are within this range). The results are that at 5% wind power penetration (of gross demand) the increase in variations is 0·5%–1%, at 10% penetration 1%–2% and at 15% penetration 1·8%–2·8% of installed wind power capacity. The effect of wind power on variations was smaller in Denmark than in Finland. This is mainly due to the relatively larger load variations in Denmark, absorbing wind variations. If the Nordic electricity market area was working without bottlenecks of transmission, 10% of wind energy distributed in the area would require extra flexibility of less than 1% of installed capacity at 10% wind penetration (of gross demand).

The estimation is based on hourly wind power and load data from three years. The years were less than average wind years, meaning that the hourly variations could be underestimated. The underestimation in these results, due to less than average wind resource during the study period 2000–2002, is of the order of 4%–6% only.

The estimates of increase in hourly variations do not take into account the fact that the variations are easier to predict for the load than for wind power production. To estimate the effect of load and wind forecasts on these analyses, a case for Finnish year 2001 load estimates was run based on the information from year 2000 load data. This analysis showed that the results above, based on the simple hourly variations from load and wind power time series, should be increased by 50%–100% depending on the level of wind power forecast (no forecast versus forecast being 20% better than not using any). This means that, when producing 10% of yearly electricity consumption with wind power, the increase in hourly variations would be 1·5%–4% of the installed wind power, instead of 1%–2% neglecting the forecasts. More specifically, for Denmark the 2000 MW of wind power would increase the hourly variations by 30–40 MW, for Finland the 4000 MW by 120–160 MW and for the Nordic countries the 19,000 MW by 240–320 MW. This can be used as an estimate for the increase in requirements for load-following or secondary reserve for the power system due to wind power.

The smoothing effect of thousands of wind turbines at hundreds of wind farm sites is underestimated by the wind power data sets used for Finland and the total Nordic area. This means that the estimates for the variations of wind power production are probably still somewhat conservative.

Another basic assumption is that the hourly variations give an estimate of the short-term variations relevant for operating reserve of the power system. Secondary reserve is operated in 10–15 min. Hourly data are used here, as 15 min data are very limited and would not allow for a large-scale system study. However, as the wind varies less within an hour than on an hourly basis, using hourly data would not underestimate the effects. The results from a study from Ireland suggest that at 10% penetration the increase in hourly variations of the net load is less than 2% of wind power capacity, whereas the half-hourly data give an increase of less than 1% of wind power capacity.[19]

The conclusion of this study is that the hourly variations of large-scale wind power will be seen as an increase in the hourly variations and thus operating reserve requirements of the power system. The impact will increase the larger the share of gross demand produced by wind power. At a 10% wind power penetration level this is estimated as 1·5%–4% of installed wind capacity, taking into account that load variations are more predictable than wind power variations.

The costs of this increase in operating reserves, as well as electricity market studies, focusing on longer-term variations of wind power, are subjects for future work.

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A Multi-Turbine Power Curve Approach

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Abstract: **A simple methodology is described – the multi-turbine power curve approach – a methodology to generate a qualified estimate of the time series of the aggregated power generation from planned wind turbine units distributed in an area where limited wind time series are available. This is often the situation in a planning phase where you want to simulate planned expansions in a power system with wind power. The methodology is described in a step-by-step guideline.**

Index terms: Aggregated power, power curve, power planning tool, wind power.

I. INTRODUCTION

The wind speed varies in both time and space, and the correlations between the wind speeds in two points in time or space will decrease with increasing time or distance.

The power in the wind is proportional with the cube of the wind speed

$$P_w(u) = \tfrac{1}{2}\rho A u^3 \qquad (1)$$

where ρ is the air density, A is the area of the cross-section of the 'flow tube' and u is the wind speed.

The electrical power output from a wind turbine can be expressed as

$$P_e = C_P \times P_w \qquad (2)$$

where

$$C_P(u) = \frac{P_e}{P_w} \qquad (3)$$

is the wind turbines efficiency coefficient. C_P increases with the wind speed from zero until its maximum (≈ 0.5 at 6..10 m/s, depending on the turbine design), and decreases with higher wind speed in order to limit the power output to the rated level (see Figure 1).

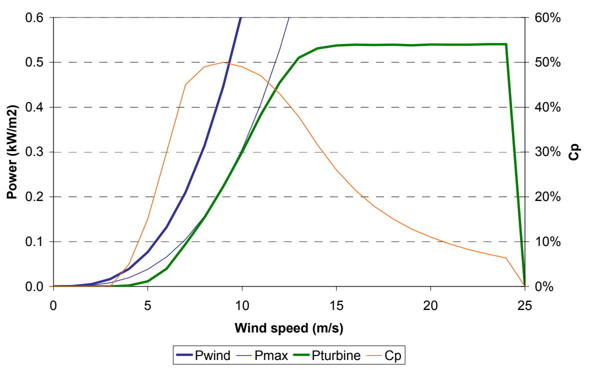

Figure 1: Illustration of the power output from a single wind turbine relative to the power in the wind (and the power in the wind multiplied with a fixed factor: 0.5). In addition, the turbines efficiency coefficient, C_p, is indicated.

The power output from a single wind turbine unit will therefore for the lower wind speed levels (4..8 m/s) be even more sensitive to the variation in wind speed than expressed by Eq. 1.

The rapid short-term, small-scale fluctuations in the wind speed are in some degree smoothed out at the power output from a single wind turbine unit, both by the extent of the rotor (up till 100 m rotor diameter for a modern large-scale wind turbine) and by the power control of the wind turbine (stall, pitch, variable speed etc).

The aggregated power generation from more wind turbine units in an area, P_Σ, will further smoothen out the short-term fluctuations, as the power generation from the individual units are not fully correlated. In general, the more units and the larger distance between the units, the lower level of the high frequency fluctuations in the aggregated power generation.

When modelling (e.g. on hourly time basis) potential developments of integrated power systems with wind power potentials, detailed information of the wind power potential for the areas of interest are often not available. Typically, the information of the instantaneous wind resource for an area is available in terms of one time series of the wind speed only, valid only for the specific site, but representative for the entire area.

Therefore, you need to be able to simulate a time series of the aggregated power generation from a cluster of wind turbines on the basis of the time series of the wind speed in a single point; or alternatively on the basis of a time series of the power generation from a single unit or a smaller cluster of wind turbines.

However, a qualified sample of a time series of the aggregated power output from multiple (but similar) wind turbines can be derived based on this one point wind speed time series and a standard power curve for a single wind turbine, representative for all the wind turbine units in question, by taking into account the smoothing effects in both time and space.

The methodology presented in the present paper is a simplified multi-turbine power curve approach to simulate the smoothing effects of the aggregated power output from a number of wind turbines within an area. It has been developed as part of the EU supported WILMAR project[1].

The model

Based on only one wind speed time series representative for the area, and a standard wind turbine power curve representative for the wind turbines, the methodology presented will provide a qualified sample of a time series

[1] WILMAR – Wind Power Integration in a Liberalised Electricity Market (EU Contract No: ENK5-CT-2000-00663).

of the aggregated power generation from a number of (similar) wind turbine units within an area. The extent of the area may vary from few kilometres (corresponding to a wind park) to several hundred of kilometres (representing a region). For this purpose an artificial, empiric based 'multi-turbine power curve' representative for the aggregated power generation has been developed. The methodology take into account the smoothing effects in both time and space. The methodology has been verified by real data and compared to using no smoothing and to using a standard power curve for the wind turbines.

The inputs needed are:

1. a wind speed time series representative for the area;
2. a standard wind turbine power curve representative for the wind turbines to be covered; and
3. the dimension of the area.

The methodology is described in a step-by-step guide including:

- The wind is characterised in terms of the wind speed distribution, the mean wind speed and the turbulence intensity.
- The wind speed time series is adjusted to relevant hub height and smoothed by a moving block averaging using a time slot representing the propagation time over the area.
- The 'smoothed power curve' is found based on a representative standard power curve and the standard deviation of the spatial wind speed distribution, and scaled appropriate to represent the total installed wind power capacity.
- The aggregated wind power time series is finally derived by applying the smoothed and scaled power curve to the smoothed and adjusted wind speed time series.

II. AGGREGATED WIND POWER

The aggregated instantaneous power output, P_Σ, from a number of wind turbines within an area (e.g. a cluster, a wind farm or a region) is simply the sum of the simultaneous power output from all the individual units within the area, P_1, P_2, ...

$$P_\Sigma = \sum_i P_i \qquad (4)$$

Due to the spatial distribution of the individual wind turbine units (the distances between the units) in combination with the stochastic nature of the wind speed, the power outputs from the individual units within the area are not necessarily the same at the same time. The simultaneous power outputs from the wind turbines will be distributed around an average value. The deviation of the distribution depends on the extent of the area in question and the turbulence in the wind.

The fluctuations of the wind speeds at the individual units (and thereby of the power outputs from the units) will be more or less correlated in time – depending on the distances between the units and the time scale of interest (see Figure 2). The short-term power fluctuations from the individual units will therefore be more or less smooth out in the aggregated output – depending on the number of units, the size of the area and the time scale.

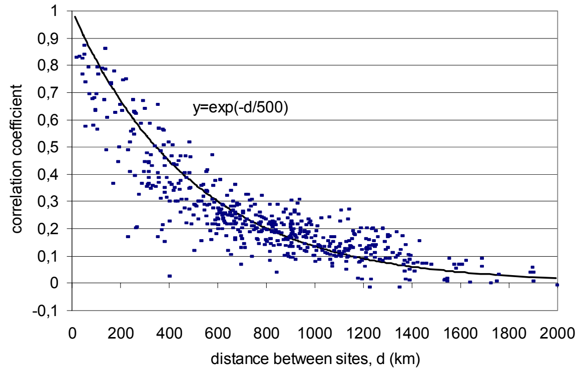

Figure 2: The power output from wind turbines correlates for sites 200-400 km apart, after which the correlation becomes weak. Hourly data from the Nordic countries, year 2001 (Holttinen, 2003)

The extent of the smoothing effect can be estimated from comparing the statistical parameters of existing single turbine, a wind farm and real production data (Holttinen, 2003). For the example of West coast Finland, year 2001 (Figure 3), the standard deviation of the hourly time series for a single turbine is 25…27 % of capacity. For the 3 clusters of altogether 8 turbines 10 km apart it is slightly less than 25 %. For 5 sites in an area stretching 200 km it is less than 21 %. As the data available does not have the same average production, it is more appropriate to compare the relative standard deviations (standard deviation / average) where we see a reduction from single turbine 1.14, wind farm 1.02 to larger area 0.93.

The reduction is more dramatic when looking at the variations from one time step to another. The hourly variations as a time series, the standard deviation is 8 % of capacity for the single turbine, 7 % of capacity for the wind farm and 4 % of capacity for a larger area, thus reduction of variations to a half of the single turbine values.

For the East Denmark (about 100 x 200 km); example in Figure 4, similar values for the standard deviations are seen for the year 2001 data. From the hourly time series, standard deviation is 24 % of capacity for a wind farm (stdev/aver 1.12) and 21 % for the whole area of East Denmark (stdev/aver 1.09). From the hourly variations time series, standard deviation is 7 % of capacity for the wind farm and 3 % of capacity for the whole East Denmark.

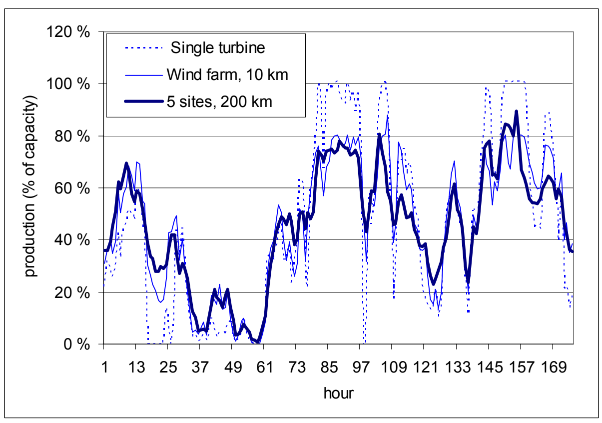

Figure 3: The power output (hourly time series) from one single unit, from a wind farm and from multiple wind farms.

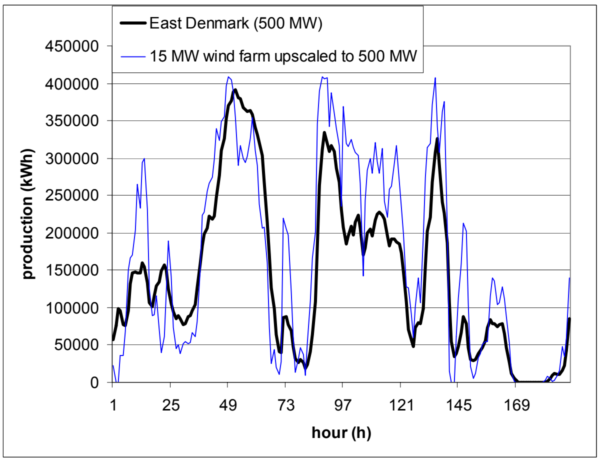

Figure 4: Year 2001 data from East Denmark.

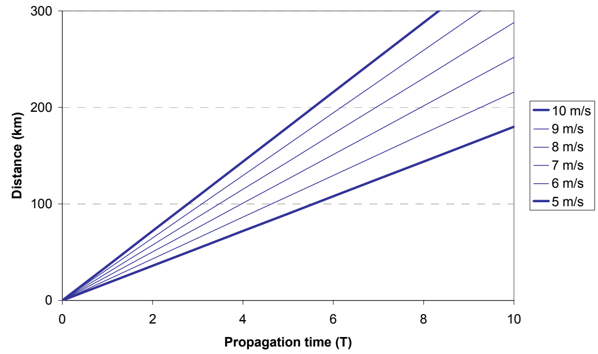

Figure 5: Illustration of the relation between the distance, D, and the propagation time, T, for the 'wind', indicated for various average wind speed levels.

III. THE METHODOLOGY

The methodology presented below (and the numbers indicated) are simplified, pragmatic and approximate, but it may be the best you can do and acceptable for an estimate. The approximations in the method on the other hands imply that the method is applicable also for a low number of wind turbines (down to 5) or wind farms (down to 3), provided that the wind turbines / farms are equally in size and equally distributed over the area. The methodology assumes that all the wind turbines within the area are similar – equal in size and control principle.

Moving block-averaged wind speed time series

As a first approximation, a change in wind speed will propagate in space in the direction of the average wind direction with a speed similar to the average wind speed. (E.g., with an average wind speed of 8 m/s a wind speed change will propagate approximately 5 km within 10 minutes, 30 km within 1 hour or 100 km within 3 hours.) A wind speed measured upfront the area relative to the wind direction will thus still be (more or less) represented within the area in a time period corresponding to the travelling time of the air to pass the area.

To represent this spatial 'memory-effect' of the wind fluctuations over the area in the aggregated power for the area, the original wind speed time series is block-averaged over a moving timeslot corresponding to a representative wind speed (the mean wind speed, w_m) and the spatial dimension of the area, D:

$$w_j = \tfrac{1}{N+1} \sum_{i=j-\frac{N}{2}}^{j+\frac{N}{2}} w_i \qquad (5)$$

where w_j is the j^{th} element in the generated moving averaged time series, and w_i is the i^{th} element in the original time series. The number of points to include in each averaging process is

$$N = T/\Delta t \qquad (6)$$

where T is the propagation time and Δt is the time step in the time series (N should be an even number). Figure 5 illustrates the propagation time, T, as function of the average wind speed and the dimension of the area. The new time series generated by the moving average of the original will have the same time step as the original. (E.g. for an area with a dimension, D, of 200 km and a mean wind speed, w_s, of 8 m/s, the resulting wind speed time series is derived from the original by moving block-averaging all the numbers in the original wind speed time series within a timeslot, T, of 200km / 8m/s = 7 hours around the actual time. If the time step in the time series is 10 minutes, N becomes 42.)

Spatial wind speed distribution

In addition, the various wind speeds at the individual wind turbine units will at any specific time be distributed around the average wind speed. As a first approximation, the distribution of the individual simultaneous wind speeds at a given time is normal distributed around the block-average wind speed for the corresponding timeslot as specified above (see Figure 8). The normalised standard deviation (relative to the mean wind speed) of the distribution depends on the spatial dimension, D, of the area and the wind turbulence intensity, I (see Figure 6).

The multi-turbine power curve

If the distribution in Figure 8 of the wind speed around the block-average values is applied on the power curve representative for a single unit (Figure 1), you will get a smoothed multi-turbine power curve, that is representative for the aggregated power output for the wind turbines within the area (see Figure 7).

The j^{th} element of the (discrete) multi-turbine power curve, Pm_j, is found by the sum

$$Pm_j = \sum_i Ps_{j+i} \times ps_i \qquad (7)$$

where Ps_j is the j^{th} element of the (discrete) single-turbine power curve and ps_i is the probability of the spatial distribution in Figure 8. (In practice the sum should as a minimum be done for a wind speed range from −5 m/s to +5 m/s around the j^{th} element in the power curve.)

Adjusting the energy production

The estimated annual energy productions for a given wind speed distribution based on the two power curves in Figure 7 should be equal. In the present methodology this is obtained by a minor offset adjustment of the distribution function in Figure 8. The necessary offset adjustment depends on the actual power curve, the wind

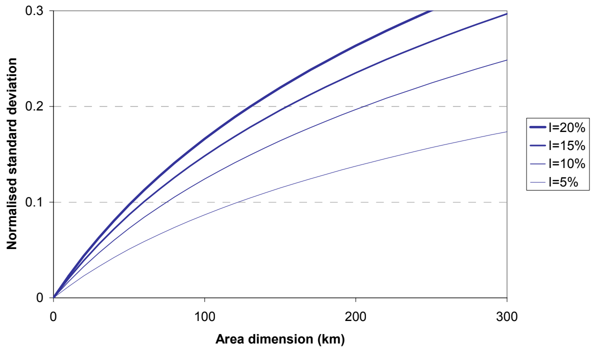

Figure 6: The normalised standard deviation of the distribution of the wind speeds at the individual wind turbine units at any given time (see the example in Figure 8) as function of the dimension of the area, D, and wind turbulence intensity, I. (Still to be further empiric validated)

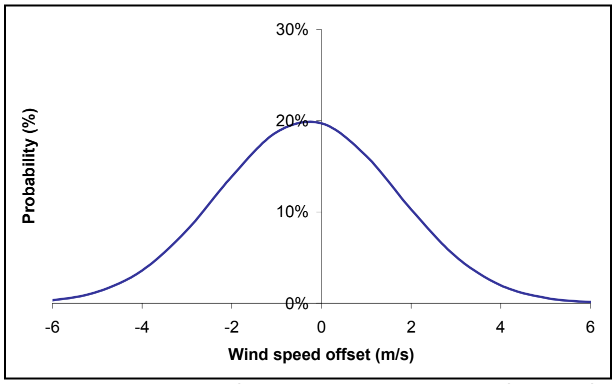

Figure 8: An example of the probability distribution function for the wind speeds for the individual wind turbines in an area at a given time (the wind speed indicated in the graph is relative to the block-average wind speed for the timeslot). The distribution indicated has a standard deviation of 1.5 m/s, corresponding to e.g. a spatial dimension of 200 km, an average wind speed of 8 m/s and a turbulence intensity of 10 % (see Figure 6). An offset adjustment of –0.15 m/s results in an unchanged accumulated production for the two power curves and the given wind speed distribution.

speed distribution in time (the Weibull distribution) and the wind speed distribution in space (the normal distribution). The appropriate adjustment must be found by manual iteration.

Finally, the multi-turbine power curve should be appropriately up-scaled to form the aggregated power curve that matches the total wind power capacity within the area.

Wind power time series

This aggregated power curve in combination with the block-average wind speed time series can then be used for an estimation of a time series of the aggregated power generation (with the same time resolution as the original wind speed time series). The aggregated power curve will at the lower wind speed levels result in a higher average power generation per unit than for the single unit and at the higher wind speed levels result in a lower average power generation. This is also reflected in the changes of the normalised annual energy production distributions (the statistical distribution of the contribution per rotor swept area to the annual energy production) as a function of the wind speed for a given wind speed distribution (see Figure 9). The energy distribution function for the multiple-turbine power curve is wider and more flat relative to the single-turbine power curve, while the accumulated normalised annual energy production remain unchanged.

The time series for the aggregated power output from the wind farm is simply obtained by applying the time series of the block-averaged wind speed on the aggregated multi-turbine power curve for the multiple wind turbines.

The methodology – step by step

Below is a step-by-step guideline for the application of the methodology at a given set of data:

1. Specify a representative dimension of the area, D – the extent of the area.
2. Specify the wind speed distribution representative for the area (e.g. given by the two Weibull distribution parameters – the scale factor, A, and the form factor, k), the mean wind speed, w_m, and a representative wind turbulence intensity, I.
3. Generate a new wind speed time series from the original wind speed time series by applying a moving block-average of the elements in the original time series in a timeslot around the specific time corresponding to the dimension of the area, D, and the

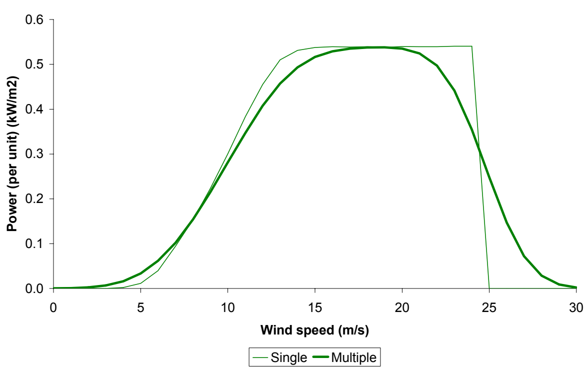

Figure 7: The distribution function of Figure 8 applied on a normalised power curve, representative for a modern large-scale wind turbine, resulting in a smoothed normalised multi-turbine power curve, representative for the aggregated power output from the multiple wind turbines within a given area.

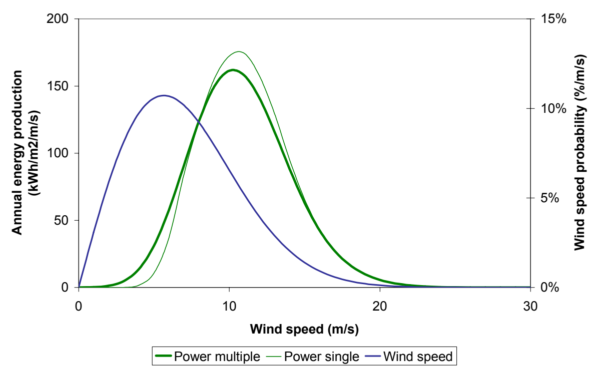

Figure 9: The normalised energy production distributions (in annual kWh/m^2) as a function of the wind speed for the single-turbine power curve and for the multiple-turbine power curve of Figure 7 respectively for a given wind speed distribution (a Weibull distribution with A = 8 m/s and k = 2 has been used). For this example the accumulated normalised annual energy production is 1300 kWh/m^2 (the same for both power curves).

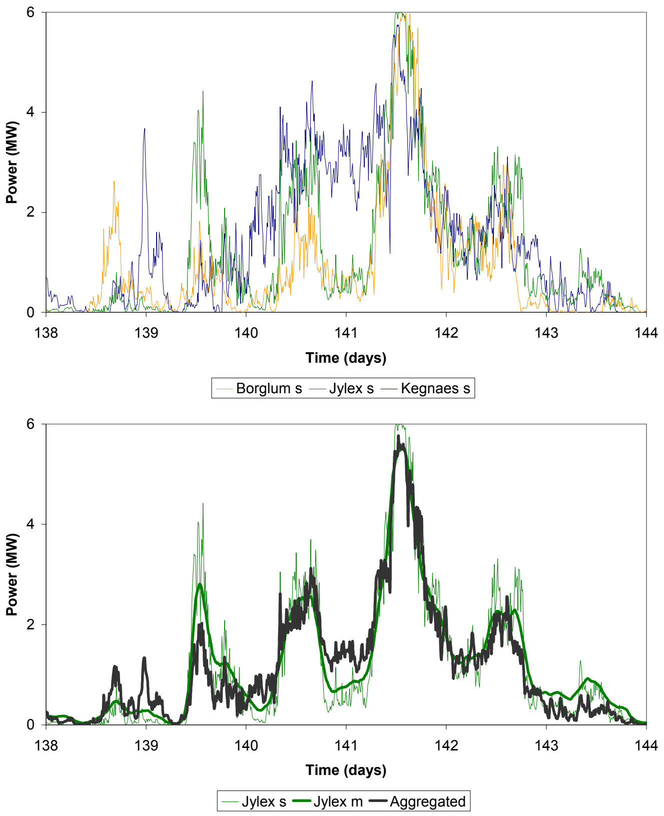

Figure 10: a) Wind power time series based on real wind data for single wind turbine units at the sites Borglum, Jylex and Kegnaes in Denmark, distributed several hundreds kilometres. b) Actual and simulated aggregated power time series of the time series in a) (simulated based on the Jylex data).

mean wind speed, w_m (see Figure 5).

4. Identify from Figure 6 the appropriate normalised standard deviation, σ_n, of the spatial wind speed distribution. Find the actual standard deviation (in m/s) to be used, σ_w, by multiply with the mean wind speed, w_m.
5. Generate the normal distribution with the given standard deviation, σ_w.
6. Identify a (normalised – kW/m^2) power curve, representative for all the wind turbines in question.
7. Generate the aggregated multi-turbine power curve by applying the normal distribution on the standard single-turbine power curve as specified in Eq. 7.
8. Apply the wind speed distribution in time (the Weibull distribution) to the two power curves, check the (normalised) annual energy production, and adjust the offset of the spatial wind speed distribution (the normal distribution) until the energy productions are equal.
9. Generate the actual aggregated power curve for the area by up-scaling the normalised multi-turbine power curve appropriately (to match the total installed wind power capacity).
10. Generate the wind power time series for the area by applying the aggregated power curve to the block-averaged wind speed time series.

Figure 11: Map indicating meteorological stations in Denmark with on-line data viewable on Risøs web-site (www.risoe.dk/vea-data).

IV. Results

The methodology is demonstrated in Figure 10. Wind data from 3 stations in Denmark (Borglum, Jylex, Kegnaes) has been used (see Figure 11). The wind power from single units at the three sites has been calculated based on measured wind data. The sum of the wind power generation from the three wind turbine units (the aggregated wind power) is compared to the simulated aggregated wind power based on only the Jylex data. The simulated time series reproduce some of the qualities in the real aggregated time series – e.g. less tendency to go to zero and max production and smoothing out the rapid, large fluctuations. Only three wind turbine units are included in the real aggregated time series, and rapid, small-scale fluctuations are therefore still present. The simulated time series don't reproduce this.

V. Conclusion

The smoothing effect of the wind power fluctuations in the aggregated power generation from distributed wind turbines has been illustrated by real data. The multi-turbine power curve approach has been described and demonstrated. The methodology is very simplified and is not able to simulate all the qualities in the aggregated wind power time series, but it's better than doing nothing, and it might be the best option.

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The effect of large scale wind power on a thermal system operation

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Abstract—**The impacts of large-scale wind power to a thermal system have been simulated for the West Denmark power system. The West Denmark power system is characterised by large transmission capabilities to both the Nordic and Central Europe systems. The exchange to neighbouring countries has been part of the simulations, with different scenarios for transmission possibilities and prices at the market. Wind power was increased at 10 % intervals, from 0 to 40 % of wind power penetration of gross demand (energy). The goal was to see the change in exchange, surplus power, emissions, thermal efficiency and regulation, due to increasing amounts of wind power.**

According to the simulations, wind power will increase the exports and decrease the imports to West Denmark. The total efficiency of the thermal power and heat production will be slightly increased due to wind power. This is due to better total efficiency for heat and power plants when operating at lower power to heat ratios. However, there will be increased cost per produced MWh for the thermal system, as the wind power penetration gets higher. The value of wind power is near average market price for the first 10 % of wind power, reducing as penetration increases.

At 40 % penetration level, only half of the increased regulation due to wind power forecast errors can be provided by the existing thermal power plants, if there is no transmission capacity and not all CHP plants participate in the regulation. If transmission capacity is included in the simulation, most of the down-regulation will come from exchange. Increase in total start-up costs for the system and decrease in emissions can only be seen for the no transmission case.

Most of the effects of wind power are dissipated to other parts of the power system than the West Denmark area studied, with the transmission possibilities to neighbouring countries available. This is a reasonable result from simulating a small area in a large power system, but also rises discussion in the paper about the ability of scheduling models' ability to capture the effects of large-scale wind power to the system operation.

I. INTRODUCTION

EFFECTS of wind power on power systems include effects on the losses in generation, transmission and distribution, effects on requirement of reserves, as well as reduced fuel usage and emissions. The impacts of wind power depend on the penetration level of wind power in the system as well as the size and inherent flexibility of the system considered.

This paper presents an effort trying to capture these effects by simulating the operation a thermal system with increasing amounts of wind power.

The impact of wind power to the system in the operational time-scale (from several minutes to several hours) is primarily driven by fluctuations in wind generation output. A part of the fluctuations is predictable 2...40 hours ahead. The varying production pattern of wind power is changing 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. A part of the fluctuations remains unpredicted, or mispredicted. This is the amount that regulation and load following reserves take care of.

Optimised unit commitment (planning the starts and shutdowns of slow-start units) is made more complicated by intermittent output from a wind resource. Even with accurate predictions, the large variations in wind power output can result in conventional power plants operating in a less efficient way. The effect on existing thermal and/or hydro units can be estimated by simulating the system in an hourly basis.

The maximum production (installed capacity) of wind power is many times larger than the average power produced. This means that at a wind power penetration of about 20 % of gross demand, wind power production equals demand during some hours (a 100 % instant penetration). Due to this, when wind power production exceeds the amount that can be safely absorbed while maintaining adequate reserve and dynamic control of the system, a part of the wind energy produced may have to be curtailed. Discarded energy occurs only at substantial penetration, and depends strongly on the operational strategy of the power system.

West Denmark is unique in its high penetration level of wind power. Several studies have been conducted, focusing mostly on the discarded energy, or critical surplus production issue. This is especially emphasised during windy, cold periods when there is also substantial share of local, prioritised combined heat and power (CHP) production (Eriksen et al, 2002).

II. DESCRIPTION OF THE SYSTEM, MODEL AND SCENARIOS

A. West Denmark, Eltra area

The system simulated is the West Denmark power system, Jutland and Fyn Island, where Eltra is the independent

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transmission system operator. There has been a high wind power expansion in the area, especially in 1996–2000. This has been accompanied with an increasing decentralised CHP expansion. In Denmark the independent system operators are responsible for the prioritised production (most of the wind turbines and small combined heat and power plants). In 2002, the prioritised production accounted for about half of total demand (20.9 TWh) for the area: Wind 3.8 TWh (18 %) and local CHP 6.7 TWh. The total installed wind capacity is already larger than the off-peak load level, both in winter and summer (Pedersen & Eriksen, 2003). In 2002, wind power production has reached instantaneous penetration of 100 % during one hour, which is unique in the world.

West and East Denmark are not connected, and are part of separate synchronous systems. West Denmark is part of the large Central Europe synchronous system (UCTE) and has sea cables to South Sweden and Norway by automised DC links (Nordel system), thus operating also in the Nordic electricity market Nordpool.

B. Simulation model SIVAEL

SIVAEL is a simulation model for electricity and heat production planning purposes, developed in Denmark (Pedersen, 1990). It is an hourly dispatch/unit commitment model, scheduling the starts and stops as well as unit production rates of power and heat.

Hourly load and heat demand are given as input, based on profiles, and contain no forecast errors. The production system is described in detail, all larger units separately and the smaller units grouped. There are planned revisions for each power plant, as well as stochastic outages according to given probability and average length of outages, modelled as events.

The scheduling is based on minimising the total variable costs, including operational, maintenance and start-up costs of both electricity and heat production. Operational constraints in the optimisation are fulfilling the electricity and heat demands, while taking care of reserve requirements given as input. Unit commitment involves dynamic programming, and there is an iteration loop to fulfil both the local heat demands and the electricity demand for the whole area.

Reserve requirement (spinning reserves, secondary reserves and load following) is taken into account as a given percentage of hourly load. Reserves will be allocated as part load operation of thermal plants.

Wind power production is modelled as an hourly profile (8760 hours). There are separate profiles for land and offshore wind power production. The latest version of SIVAEL has been modified to include forecast errors of wind power. The model uses the predictions for unit commitment and dispatch. The regulation need is calculated as the difference between predicted and actual wind power production, and allocated to either thermal plants or exchange (Pedersen & Eriksen, 2003).

As a result of the simulation, a start/stop schedule for the power plants, as well as their hourly production levels will be achieved. The results include fuel consumption, thermal efficiencies and emissions for all units.

For the hours that the model does not find a solution, because of either too much or too little production for the load, the model will calculate the amount missing, but continue simulating the next hour. In real life these situations would have to be handled by discarding energy or shedding loads. The amount of power that could not be used by the system (surplus production) or the amount of power that the system was lacking (shortfall of production) during one year of simulation is one result of the simulations, indicating issues for further planning in the system.

C. Simulated scenarios and input data

Simulations were run for the year 2010 power system. Electricity demand was assumed to be 23 TWh (increase of 2 TWh) and production capacities were assumed to stay at the level of today (table I). From the standard hourly profiles, peak load of electricity was 4130 MW and heat demand was 5705 MW.

TABLE I
ROUGH DIVISION OF THERMAL PRODUCTION CAPACITY AS MODELLED FOR SIVAEL (SEVERAL POWER PLANTS ARE ACTUALLY MODELLED AS HAVING SEVERAL FUELS).

	Electricity MW_{el}	Heat MW_{heat}	number of plants in SIVAEL
Total	**5012**	**13641**	**53**
Centralised power plants			7
coal	2744	2374	
gas	747	950	
CHP large			9
gas	329	326	
coal	44	105	
renewable	60	111	
CHP small			19
gas	942	1586	
renewable	146	389	
Heat only plants			18
gas	0	3300	
oil	0	4500	

TABLE II
WIND POWER ANNUAL PRODUCTION FOR THE SIMULATIONS. THE DEMAND IS SET TO 23 TWH FOR YEAR 2010.

Wind power % of demand	Wind power on land	Wind power offshore
10 %	950 MW, 2.3 TWh	0 MW
20 %	1900 MW, 4.6 TWh	0 MW
30 %	2560 MW, 6.3 TWh	150 MW, 0.6 TWh
40 %	2560 MW, 6.3 TWh	660 MW, 2.9 TWh

In addition to the thermal capacity in table I, there is 11 MW of hydropower in the system. Wind power for the simulations is presented in table II. Wind power production onshore is based on real large scale production data from Denmark, with scaling to represent a long time average year of 2400 h/a full load hours production. Wind power production for large offshore wind farms is based on wind speed measurements offshore, with full-load hours of 4000 h/a. The scenarios were run with 0 to 40 % of wind power penetration, at 10 % intervals (table II). The amount of wind power in 2003 is close to the 20 % penetration case. Wind power predictions simulated with IMM model were used (Nielsen, 2002).

Three different transmission possibilities were assumed. In a theoretical "no transmission"–scenario, West Denmark was simulated without any exchange with neighbouring countries. In a "low transmission"–scenario, only Nordic connections to Norway and Sweden was assumed, a total of 1720 MW anticipated for year 2010. In a "high transmission"–scenario, possibilities to both Germany and Nordic countries (1200 MW + 1720 MW) were assumed.

As the exchange with Nordpool (Norway/Sweden) and Leipzig (Germany) is used according to prices at the markets, the low and high transmission scenarios were run with 2 price levels at the market. The average price was set to 220 DKK/MWh in the high price scenario and 120 DKK/MWh for Nordpool and 170 DKK/MWh for Leipzig in the low price scenario. Both the high and low price scenarios use approximate daily/weekly/seasonal profiles from the electricity markets.

In addition to the standard profiles for year 2010, one case was simulated taking real data from year 2001 as input profiles (8760 h) for market prices, electric demand and wind power. The price level in 2001 was on the average 177 DKK/MWh for Nordpool West Denmark area and 179 DKK/MWh at Leipzig.

Same set of events for thermal power plant outages was used in all simulated cases, so that the timing of forced outages would not influence the comparison of the cases. Spinning reserve requirement was set to 5 % of hourly load.

III. Simulation Results

Simulations with increasing amounts of wind power in the system have been conducted. Comparisons with the base case of no wind power installed have been made, to see the changes in thermal efficiency and costs, amounts of start/stops, regulation, exchange, discarded energy and emissions.

A. *Increased exchange with neighbouring areas*

The possibility of transmission between the neighbouring areas results in different base case situations for Denmark. There will be net exports from Denmark at high price level at the market, and net imports when low price at the market. Denmark is situated in between two different electricity market areas. This results in transit through the country, especially in exceptional hydropower situations when the market prices in the Nordel area differ notably from those of Germany. Only net exports are shown in Fig. 1. For high transmission cases there is a high level of exchange, starting at 14 TWh imports / 7 TWh exports for low price case and 11 TWh exports / 9 TWh imports in high price case.

Adding wind power will increase the exports and decrease the imports. When transmission to Germany is available, this will increase both the imports and exports, as there will be transit through Denmark from Nordic countries to Germany and vice versa. For high price cases adding transmission will not result in more net exchange for Denmark, only increasing transit. Comparison with the cases using real price profiles from 2001 shows that this is really what happens in high price years, adding of the transmission capacity does not alter the net exchange. For the low price situation, net exchange is even lower when adding transmission, compared with transmission only with Nordel. This can be explained by increased transit of cheaper Nordpool electricity to Germany.

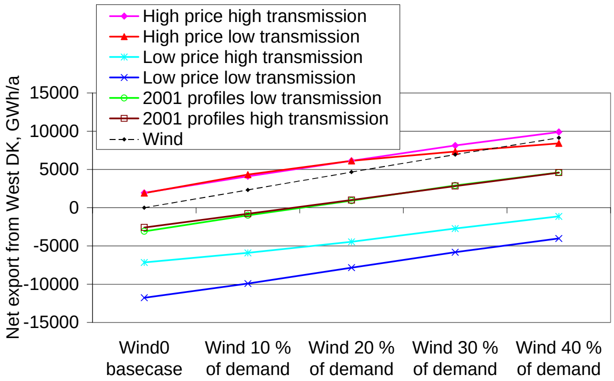

Fig. 1. Simulation results for net exports from West Denmark, when adding wind power to the system. Wind power added is shown as a dotted line.

Also wind power added to the system is shown in Fig.1. It can be seen that as wind energy is increased so is the net export. The major part of wind energy will flow abroad, even if the increase in net exchange is at a somewhat lower rate as the addition of wind power.

At 10 % penetration of wind, 80–90 % of the wind energy is exported in the various cases. The only exception is the case of low price - high transmission, where half of the wind power stays in West Denmark.

At 40 % penetration of wind 70–80 % is exported in the various cases. The only exception is the case of high price - low transmission, where most of the wind energy stays in West Denmark, as can be seen in the Fig 1.

B. *Effect on thermal system efficiency*

The simulation results include thermal power and heat production as well as the total fuel consumption. The total efficiency of the system can be calculated from these. Adding wind power will decrease the electricity produced by thermal plants. In the case of West Denmark thermal CHP system, this will actually result in slightly increased total fuel efficiency, by 0.1…1 % percentage point per 10 % wind power penetration added.

The explanation for this increase in the total efficiency of the thermal system comes from the combined heat and power production. CHP has a higher efficiency than producing only electricity (condensing power plant operation). The efficiency depends on the ratio of heat and power produced as well as the power plant characteristics. The heat demand and production is similar in all scenarios, as heat demand must be met locally, so the change in efficiency is due to different amount of electricity produced by thermal power production. For the base case high price - high transmission, the electricity produced in West Denmark is 25 TWh, and for the low transmission low price it is 11 TWh. The total efficiency varies between 70 % and 81 % respectively. When lower amount of electricity is produced, there is higher efficiency in combined heat and power production.

One effect from the fluctuating wind power is increasing the starts and stops of the thermal plants (Fig.2). The increase can actually only be seen directly when looking at the system without transmission possibilities.

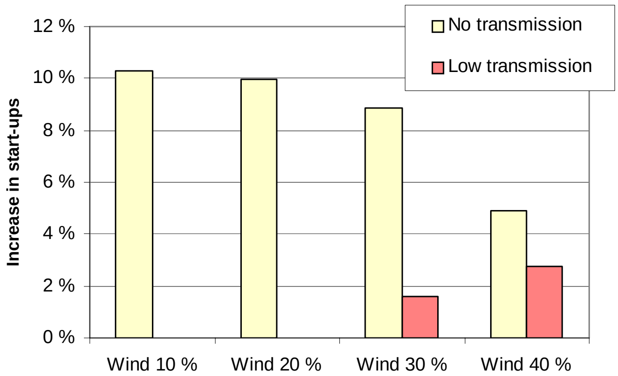

Fig.2. Simulation results for increase in total amount of start-ups in the thermal power plants, when adding wind power to the system.

The costs related to increased start-ups are seen in Fig.3. Allocating the extra start/stop costs to wind power added to the system, the cost for the first 10 % of wind power is 4.6 DKK/MWh and for the first 20 % of wind power 3.5 DKK/MWh. Having more than 20 % of wind power in the system means increased part load operation of thermal plants, and thus the starts and stops will be reduced. This extra cost will be seen as the increase in total costs of thermal power.

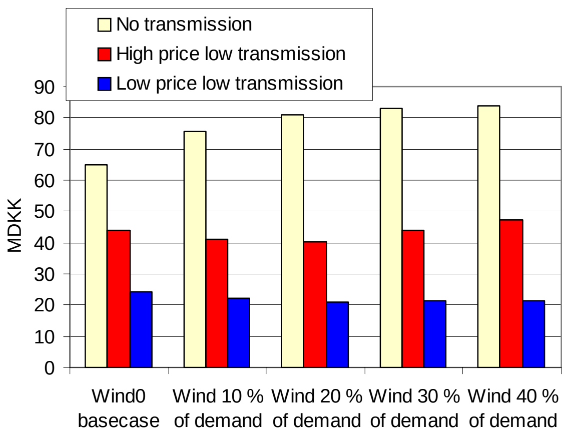

Fig. 3. Simulation results for start/stop costs from West Denmark, when adding wind power to the system.

For the cases with exchange, there is hardly any effect on the start up costs. The exchange is used to smooth out the variations, so that the start and stop cycles of thermal plants are not very much affected by wind power. Only low transmission cases are shown in Figs. 2 and 3 – the high transmission cases do not show any different behaviour. The level of the costs is 45 and 30 MDKK for high and low price, respectively, and increasing the wind power level does not make any significant trend in the costs.

C. Effect on thermal system costs

Wind power will replace electricity production from other sources, thus reducing the fuel costs. This reduction in fuel costs, allocated to the wind energy increased, will give the value of wind power to the system. In this value, also the difference in costs related to starts and stops, as well as maintenance costs have been taken into account (Fig. 4).

The total (operating) cost per MWh to the system is at the level of 230 DKK/MWh for the base case no transmission. Adding wind power increases the total costs by 15 % in the case of 40 % penetration. For other base cases, excluding costs from market exchange, the average thermal production costs in West Denmark range from 220 to 300 DKK/MWh depending on the level of production and net exports. Adding wind power increases the total costs by 4–5 %, except for the high transmission cases, where there is either not much increase (at high price level) or higher increase of 9 % (at low price level). As the wind power penetration gets higher, there will be increased cost per produced MWh for the thermal system, and thus reduced value of wind power.

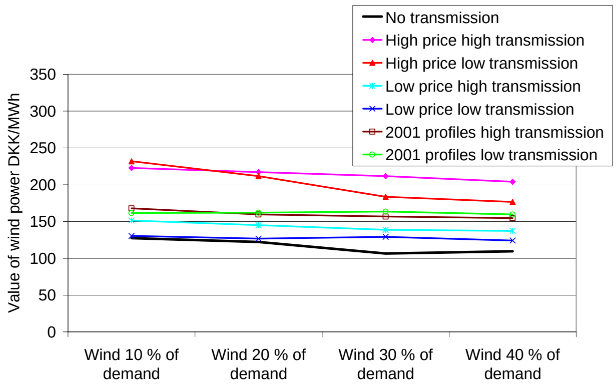

Fig. 4. Simulation results for reduction of costs due to added wind power: value of wind power to the system.

The value of wind power for West Denmark when operating without exchange is about 140 DKK/MWh, decreasing to 110 DKK/MWh at high penetrations. The value of wind power is higher when the price level at the market is higher, because then also wind power will get higher price at the market, and more expensive capacity will be operating for the wind power to replace in West Denmark. When the price level at the market is high the value is 220…200 DKK/MWh and when the price level is low, the value is 150…140 DKK/MWh. These are the results for high transmission capacity. When the transmission capacity is limited, the value of wind is somewhat higher.

At first the value of wind power is slightly higher than the market price, but it will drop as the penetration level increases. The market prices used with standard profiles do not reflect the influence of wind power production to the price level. The profiles and prices for year 2001 have this impact implicitly included, as there was already a substantial penetration level of wind power in West Denmark. This explains why the 2001 profile simulations result in value of wind power slightly lower than average market price.

D. Discarded energy

For the purely theoretical assumption of no transmission possibilities, Eltra system as described to the model for year 2010 would not operate reliably without wind, as there would be occasions of power lacking. In this case, wind power added would actually help the situation until 10 % penetration: even if surplus production occurs, it is less than the original lack of power. Significant amounts of critical, non exportable surplus power start to occur at 20 % penetration and this will increase more than linearly, reaching 1.5 TWh at 40 % penetration.

If there is low transmission assumed (only Nordel), the problem with surplus production will start when wind power penetration is more than 20 %, or, if the price at the market is low, only after 30 % penetration. The amounts are not very high: less than 0.2 TWh at 40 % penetration.

If there is high transmission assumed, both Nordel and Germany anticipated capacity in 2010, the surplus problem first arises at 50 % penetration.

E. Regulation due to wind power

Increased regulation due to wind power is an issue for all operating time scales of the power system. For the second/minute time scales of frequency reserves, this cannot be directly simulated by an hourly simulation model like SIVAEL. The effect of reserves, both spinning and load following, are taken into account by addressing the amount of 5 % of hourly demand to part load operation of power plants, as a requirement for reserves.

For the 15-minute to hour time scale of load following, the effect of prediction errors can be simulated, and the latest version of SIVAEL can take this into account for wind power. The model will allocate this extra regulation to either the central power plants, or to exchange with neighbouring countries. If these options are fully consumed, then the regulation is increasing the surplus or lack of power to the specific hour.

The prediction error comes from a stochastic simulation. The total prediction error for the year, as % of total wind power production, is 20 % in these simulations. This is lower than the state-of-the art for 12–36 hours-ahead errors for Denmark, but actually represents the current prediction error for up to 6 hours ahead. This is more relevant for the thermal power plant scheduling, if not quite in line with the day ahead spot market operation today.

It is worth noting that the amount of regulation due to wind power comes directly from the simulated prediction errors for wind power only. So the increase in regulation due to wind has been this 20 % of the wind power production in all the simulations.

When simulating the West Denmark area without exchange, the extra regulation need due to wind power is taken from the primary, central power units to the extent possible. For the first 10 % of wind energy, 20 % of the down-regulation needs result in surplus energy and 10 % of the up-regulation needs result in lack of energy. These situations will increase as wind power penetration increases, so that for 40 % penetration the thermal power plants will be able to provide only a half of the energy needed for regulation.

When simulating with exchange possibilities, the thermal power plants in West Denmark are used for about half of the up-regulation and only about 10 % of the down-regulation needs, the rest is from the exchange. This is the situation for 10 % wind power penetration: when increasing the penetration level, more exchange is used for up-regulation and less for down-regulation.

For low transmission cases the error in wind prediction will increase critical surplus situations, after 20 and 30 % penetration as described before in section D.

In the simulations, only the centrally operated power plants are involved in load following regulation. The prioritised, smaller scale CHP plants could also provide this service. Some estimated have been made (Pedersen & Eriksen, 2003), that suggest this could have an important value for the handling of prediction errors in West Denmark.

F. Effect on CO_2 emissions

When wind power is replacing electricity production and fuels for conventional fossil-fuelled power plants, there will be a reduction of emissions.

The only straightforward results for CO_2 effect of wind come from no transmission -scenarios, where all wind power will be replaced inside West Denmark. For the total fuel consumption in base case coal presents roughly half, gas a third, renewables (waste, straw, wood chips) 10 % and oil 2 %. Wind power will decrease mostly coal and gas, but at high penetrations also effects on renewables can be seen, and the low oil part will actually increase some. The first 10 % share of wind power will reduce 450 g CO_2 per each kWh produced. A 10 % increase from 30 to 40 % penetration level will result in lower abatement: 350 gCO2/kWh.

When transmission possibility is included, but the reduction of fuel use is calculated from only West Denmark, the reduced emissions from thermal production versus the wind power added will give modest values (50…200 g/kWh). This is due to the added exports. When addressing a value of 700 g/kWh to the increased net export amount (Holttinen and Tuhkanen, 2003), this gives a result of 600...700 g/kWh for the CO_2 abatement of wind power in Denmark.

IV. Discussion

It is not straightforward to model wind power production with the existing scheduling models, as explained in Dragoon & Milligan, 2003. There are problems relating to the modelling of large-scale wind power: the hourly variations and prediction errors of wind power should be representative of large scale wind power with geographical smoothing in the production patterns. The uncertainties should be modelled for different time scales of unit commitment (starting and shutting down slow thermal units) and dispatch (production levels of thermal units). Problems can also emerge from the simulation logic in itself: optimisation of the system can be fundamentally different if taking into account the different nature of wind power production. Also regulation requirements are often not modelled directly, but coming from years of operating experience, so the effect of wind power cannot be modelled either. Modelling of market interactions and price levels should also be looked at when simulating wind power in the system.

In these SIVAEL simulations presented here, wind power production has been modelled in detail, with also prediction errors. The data for actual production is representative for large scale wind power, as it is realised production of thousands of wind turbines in Denmark. However, the prediction errors are simulated, and that part could still be improved, especially concerning the time scales that are relevant for the unit commitment and dispatch. In these simulations there is an effort trying to look at different market price levels and situations (exchange possibilities). However, at large penetrations there will be influence of wind power on the market prices, and this has only partly been included when using the 2001 data for simulations. For the underlying logic in optimising, there is not wind power taken into account specifically, but this will be subject to changes in the next version of the model. When studying the effect of wind power on regulation, it has to be taken into account that the imbalance is dealt with on a control area basis. Every change in wind output does not need to matched one-for-one by a change in another generating unit moving in the opposite direction, but the aggregation must be balanced. Here only regulation due to wind power has been studied. For high penetrations in West Denmark, most of the imbalance comes from wind power. It would be interesting to see the effect when load forecast errors would be present in the simulations.

The results here are of a theoretical study, increasing wind power while keeping the rest of the system the same. With large increased capacity and production, this results in over capacity of production, when no other capacity is withdrawn. This can be one thing explaining the large increased net exports.

All in all, capturing the effects of wind power on a power system is not an easy task. The effects are spread over the total control area (synchronously operated area) or electricity market, with constraints on transmission capacities between the areas. Modelling a small part of the area has to take into account these transmission capacities, but as wind power in the neighbouring area is not modelled, the use of exchange can be overestimated in the simulations. Also there can be an effect on the available transmission capacity due to wind. Contingencies, due to dynamic phenomena, cannot be modelled with an hourly time scale model. Due to this, the low transmission possibility scenario is often used.

Comparison to results from other similar studies can be made in regard to discarded energy. Some studies have been made for thermal systems, taking wind power production in but leaving the thermal plants running at partial load even at high winds to provide regulation. The results are that at about 10 % (energy) penetration, the curtailment needs for wind power will start, and at about 20 % penetration discarded energy will become substantial, losing about 10 % of the total wind power produced (Giebel, 2001;CER/OFREG NI, 2003). This corresponds to the results presented here for the no transmission capacity case. For West Denmark, earlier simulations of the system resulted in significant discarded energy at high penetrations, when disregarding the transmission capacity to Germany: a 1.3 TWh critical surplus energy at 12 TWh wind power production, a 50 % penetration (Lund & Münster, 2003). This is a higher surplus than estimated here for the corresponding low transmission case (less than 0.2 TWh at 9.2 TWh production, a 40 % penetration). The reason is that here the CHP capacity that can be operated flexibly is higher. For the earlier results, it has been estimated that nearly 50 % wind power penetration could be accommodated with minor losses of discarded wind energy. This requires using the existing heat storage and boilers of CHP production units in collaboration of wind power, together with some flexible demand and electrical heating (Lund & Münster, 2003).

The CO_2 abatement of wind power in an area that is part of a larger system is especially difficult to catch. What production do the net exports really replace, when there is the low transmission scenarios with exchange only to hydro power dominated Nordel? Actually, this is a theoretical question as it is a theoretical case of only Nordel exchange, and in real life net exports would probably be to Germany and reduce their coal condense power production. When wind is replacing imports from Nordel on a wet, low price year, then either wind will actually have no CO_2 benefit, or the hydro power is just moved on to Germany.

The results from the different transmission scenarios show that there is not so much effect on the local system but to the exchange. This can be a real and valid result – even if wind power penetration level in West Denmark and North Germany is high, it is not high in all Central Europe system.

V. Conclusions

The impacts of large-scale wind power to a thermal system have been simulated for the West Denmark power system. The exchange to neighbouring countries has been part of the simulations, with different scenarios for transmission possibilities and prices at the market. Wind power was increased at 10 %

intervals, from 0 to 40 % of wind power penetration of gross demand (energy).

According to the simulations, wind power will increase the exports and decrease the imports to West Denmark. A major part of wind energy is exported to neighbouring countries. This effect will decrease as the penetration level of wind power increases.

There will be a slight increase in the total efficiency of all thermal combined heat and power plants in West Denmark as wind power is added to the system. This is due to better total efficiency for heat and power plants when operating in lower power to heat ratios.

The increase on total start and stop costs of the thermal power plants can only be seen when simulating the system without transmission possibilities. Allocating the extra start/stop costs to the amount of wind power added to the system, the extra cost for the first 10 % of wind power is 4.6 DKK/MWh and for the first 20 % of wind power 3.5 DKK/MWh. Having more than 20 % of wind power in the system means increased part load operation of thermal plants, and thus the starts and stops will be reduced.

Extra cost of part load operation is seen as the increase in total costs of thermal power. There will be reduced value of wind power and increased cost per produced MWh for the thermal system, as the wind power penetration gets higher. The value of wind power is higher when the price at the markets is higher. The value is nearly at the market price level for the first 10 % of wind power, reducing as penetration increases.

At high penetration levels, a part of the wind energy will have to be curtailed in order to maintain a reliable system operation. According to these simulations, critical non exportable surplus production would occur after 20 % penetration for low transmission possibilities.

The effect of wind power on CO_2 emissions in West Denmark are only seen when simulating the system without transmission possibilities. At 10 % wind power penetration wind power decreases the emissions at the rate of 450 gCO_2/kWh. A 10 % increase from 30 to 40 % penetration level will result in lower abatement: 350 gCO_2/kWh.

The simulations presented included prediction errors for the wind power production. The total amount of prediction error presented about 20 % of the wind energy produced. The model allocated the extra regulation due to prediction error to either increased part load operation of centralised thermal power plants or to exchange. According to the simulations, most of the down regulation and half of the up regulation was handled with changing exchange. Adding wind power would result in more thermal plants reacting for the down regulation, and less for up regulation. If no transmission was possible for the system, at 40 % penetration of wind power the thermal power plants would be able to provide only half of the energy needed for regulation.

Capturing the effects of wind power on a power system with simulation models is not straightforward. Most of the effects are dissipated to other parts of the power system than the area studied. This is quite possible for the foreseeable future, because even if there is already high penetration of wind power in Denmark and Northern Germany, it is still a minor part of the total Central Europe power system.

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EFFECTS OF LARGE SCALE WIND PRODUCTION ON THE NORDIC ELECTRICITY MARKET

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ABSTRACT: Simulations with the power market model EMPS with weekly time resolution have been made to assess the effects of large scale wind production to the Nordic electricity market. Two base case scenarios are made, reference for the Nordic market area for years 2000 and 2010, and wind is added to these systems in 3 steps. The results for the simulations with 16…46 TWh/a wind production in Nordic countries (4…12 % of electricity consumption), show that wind power replaces mostly coal condense and oil as fuel for electric boilers. As a result of fuels replaced by wind production a CO_2 reduction is achieved, of 680…620 gCO_2/kWh. Indications for bottlenecks in transmission can be seen, especially to Central Europe, when the wind production is above 20 TWh/a. Average spot market price drops by roughly 0.2 eurocents per 10 TWh/a wind production added to the system. Avoided costs for wind power production are roughly 2 eurocents/kWh for today's system and 3.1 eurocents/kWh for 2010 system with CO_2 tax and reduced power surplus. Changes in socio-economic surplus for the market is 2.4…2.0 eurocents/kWh for 16…46 TWh/a wind production, i.e.15 % higher than average spot price (for 2010, 3.9 eurocents/kWh, 30 % higher than average spot price).

Keywords: Electrical Systems, Markets, Emissions, Simulations, Electricity market

1 INTRODUCTION

In the Nordic countries, the electricity system is characterised by large share of hydro power. The deregulated electricity market in the countries has led to the joint electricity market Nordpool. Wind power is still marginal in the system today (4 TWh/a) but national targets are existing for 16 TWh/a in 2010 (Denmark 8, Sweden 4, Norway 3, Finland 1 TWh/a), and considerab-ly more in 2030.

The purpose of the paper is to study the influence of large amounts of wind production to the market: differences between the spot prices, power transmission between the countries, production of hydro and thermal power, with and without wind power. This is done by running simulations on the EFI's Multi-Area Power Market Simulator (EMPS) model, a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting [1].

2 POWER MARKET MODEL EMPS

2.1 Description of the model

The power market model EMPS simulates the whole of the joint market area, instead of only one country. The market is divided into areas with transmission capacities between the areas (Fig 1). The model description used here is most detailed for Norway, which is modeled as 12 areas. Finland is modeled as one area, Sweden and Denmark as two areas. Central Europe is modeled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities.

The model simulates the market price and the production for each area with weekly time resolution. The simulation is here made for one year. Historical inflow and wind data from 30 years are used as input for the simulation to take into account the stochastic nature of inflow and wind.

The model has a good description of the Nordic hydro power system to be able to take into account the large variations in hydro inflow compensated by large storage reservoir capacities.

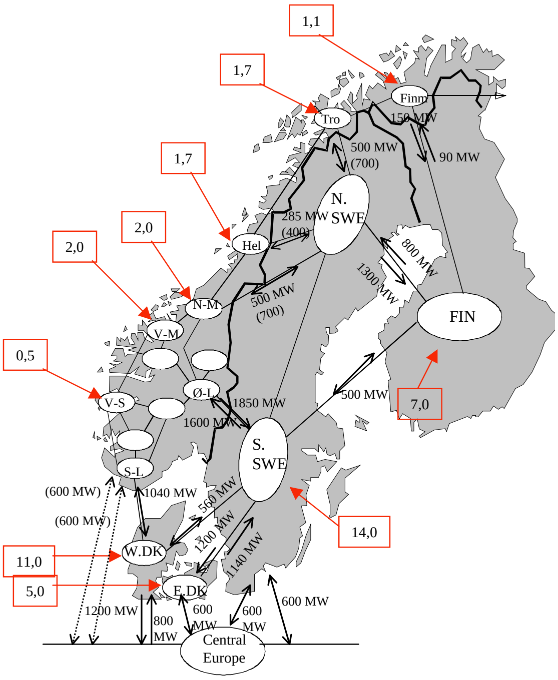

Figure 1: Areas, transmission capacities between the countries (scenario 2010 figures in parenthesis) and wind3 amounts of wind production (TWh/a) in the EMPS model.

Thermal capacity in the Nordic countries is simulated in less detail than the hydro system. Because only weekly resolution is used, no restrictions or costs of regulation or start-ups of the thermal capacity are taken into account. The model assumes that in-week variations are handled by the large hydro reservoirs in the system.

The model optimises the use of hydro power by calculating water values to the amount of water in the reservoirs, by stochastic dynamic programming algorithm. These water values vary both by the time of year and by the current and anticipated water inflow to the reservoirs. They are treated as the marginal cost of hydro power [2]. With a price to each production capacity known, the market price is determined by a market cross (Fig 2). This is done for each simulated week. If transmission capacity is restricted, there will be different prices in different areas.

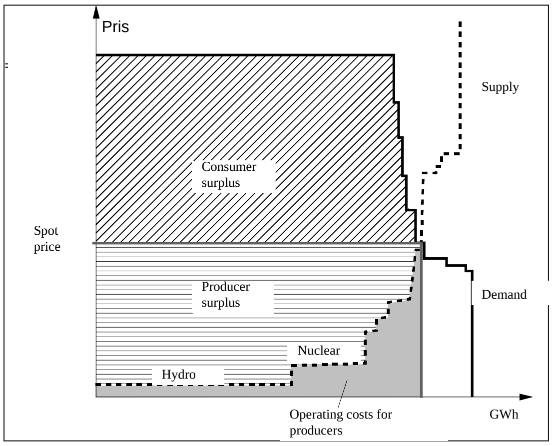

Figure 2: Market cross: the spot price calculation in the power market simulation model EMPS.

2.2 Input for the model. Reference cases.

Input data needed for each area are weekly consumption, operating costs for thermal power, maximum production (or capacity) for thermal power, detailed description for hydro power system, inflow data and transmission capacities between the areas.

The input for thermal power prices are operating costs. This is because we are simulating the bidding process in the market. In the market the producer gets the price determined by the market cross (fig.1), thus it is cost-effective for him to produce as long as the price he gets is higher than his/her variable costs. Wind energy is a price taker in the market, all that is produced will be sold, no matter what price. The marginal price is therefore 0 Euro/MWh for wind, when operating without storage, like it is for run-of-river hydro plants.

The capacities for transmission lines are shown in Fig. 2. Between Norway and Sweden lower limits for the lines than in [3] are used to take into account the technical restrictions in transmission. The production capacity is shown in table 1 for both the 2000 and 2010 base case. The thermal capacity is given either as maximum capacity [MW] or maximum weekly production [GWh]. The electricity consumption contains price elastic use of electricity mainly in Norway and Sweden. This is provided by electric boilers, which can switch from burning oil to using electricity, and also industrial consumption in Norway. Four load duration levels are used to take into account the consumption pattern inside a week.

In the scenario made for year 2010 [4] electric consumption was added by 32.2 TWh/a and production capacities were changed. For Sweden one nuclear plant was shut down, condense was shifted to biofuels and CHP was added. For Finland more CHP and coal was added [5]. For Norway a new gas power plant (400 MW) was added. For Denmark coal was shifted towards gas [6]. Improved transmission capacity was foreseen for Norway/Central Europe and between Norway and Sweden (fig.2). CO_2 tax of 15.6 Euro/tCO_2 (125 NOK/tCO_2) was added to operating costs of fossil fuels. The effect of CO_2 tax is to rise the marginal costs: for coal by roughly 12.5 and gas by 7.5 Euro/MWh. Thermal power costs in Central Europe were adjusted closer to those in Denmark and Finland to reach a balance in the market. As a result, the thermal production was up 25.4 TWh/a and price elastic consumption down 5.7 TWh/a.

Table 1: Maximum production capacity and electricity consumption as input to the EMPS model (ref2000 plain **ref2010 bold**). CHP= Combined heat and power.

	Fin	Swe	Den	Nor	Eur
Consumption [GWh/a]	78800 **90500**	142400 **152300**	34900 **37000**	120000 **121900**	567100
Nuclear [GWh/a]	21800	70800 **67000**			152900
CHP [GWh/a]	24800 **28600**	8700 **15000**	27000 **44000**		196600
Condense [MW]	3000 **4000**	400 **1200**	1800	280 **680**	42500
Gas turbines [MW]	975	195	70		
Hydro* [GWh/a]	13000	63000	3500*	115000	

*wind in DK

3 WIND PRODUCTION DISTRIBUTED IN NORDEL AREA

Wind power was added to the system in 3 phases, cases wind1…wind3, starting from 16 TWh/a (wind1) to reach 46 TWh/a (wind3) annual total production in the Nordic countries. This corresponds to 4…12 % of total electricity consumption and it is divided between the countries as 20…45 % of consumption in Denmark and 2…10 % of consumption in Sweden, Norway and Finland. Wind1 corresponds to existing targets for 2010 and wind3 is near possible targets for 2030.

Table 2: Wind power added to the system. Production in TWh/a and as % of electricity consumption today in the simulated cases.

	Wind1		Wind2		Wind3	
	TWh/a	%	TWh/a	%	TWh/a	%
Norway	3	2.5	6	5.0	9	7.5
Sweden	4	2.8	9	6.3	14	9.9
Finland	1	1.3	4	5.1	7	8.9
Denmark	8	22.9	12	34.3	16	45.7
TOTAL	16	4.3	31	8.2	46	12.2

4 WIND DATA

To catch the effect of varying wind resource, wind production was acquired from the same time period as the hydrological input data, years 1961–1990. Weekly wind production was calculated from wind measurement data. Measured wind speed was converted to power according to power curve of 1.65 or 2 MW wind turbines [7].

In Norway, wind power was added to 6 areas, based on 3 wind measurement data points in Middle and North Norway (table 3). Wind power was added to South-Sweden based on 3 wind measurement data points in Gotland and Southern Sweden. Wind power was added to both areas in Denmark, some more to West Denmark than to East Denmark. From Denmark only one measured wind speed series was available. The East Denmark production was based on South Sweden wind data, near the Danish coast.

Table 3: Weekly wind production data used as an input for the power market model.

Wind data from	Full-load hours, average	TWh/a in wind3	Weekly production, average = 100 %	
			Max	Min
Helnes, NOR	3000	1.1	158	0
Bodø, NOR	3000	3.4	171	0
Ørland, NOR	3000	4.5	196	3
Visby, SWE	2600	5.0	293	7
Säve, SWE	2600	3.0	306	0
Barkåkra, SWE	2600	11.0	298	0
Valassaaret, FIN	2200	7.0	247	2
Risø, DK	3200	11.0	262	3
TOTAL wind	**2700**	**46.0**	**221**	**14**

Large scale wind production would in reality mean production from many, scattered wind parks. Using data for few, single measurement points will overestimate the variations of wind production in a large area. As we are using weekly averages, however, this overestimation is not as profound as it would be f.ex. in hourly data.

Correlation coefficients between the weekly production series of different wind production sites were 0.11…0.76. Wind production is correlated inside Norway and Sweden, and between East Denmark and Southern Sweden. Wind production is only weakly correlated between the countries. The lowest correlation coefficients were between Southern Sweden and Northern Norway.

5 RESULTS OF THE SIMULATIONS

5.1 Effects on the energy balance between the countries

As wind production is added as extra production to the electricity system, about 30 % of the wind production is transferred out of the Nordic countries with the transmission lines to Germany, Poland and the Netherlands (in 2010 scenario about 40 %).

In Finland wind production replaces condense production (mainly coal). Import to Finland increases. For wet years in the wind3 case the nuclear production is also reduced. In Sweden the electricity consumption in electric boilers is increased with increased wind production. This means that wind production is replacing oil (alternative fuel for the boilers). Wind production is replacing condense production, for the little there is to replace, and some of the nuclear and CHP production. Export of electricity is increased substantially. In Norway the consumption in electric boilers increases with added wind production. Export is also increased. In Denmark wind is replacing condense (mainly coal) and increasing export. Both imports and exports in Denmark are increasing with increasing wind in the system.

For the cases wind2 and wind3 there are indications of bottlenecks in transmission in all lines to Central Europe, especially from West Denmark to Germany. Between Norway and Denmark, Norway and Sweden, and within Norway added wind production helps out the situation during dry years but makes some bottlenecks during wet years more profound (these lines have bottlenecks already in the reference cases). Between Sweden and Finland and inside Sweden even a large-scale wind production does not make a substantial increase in the use of transmission lines compared to the reference. However, more detailed time resolution would be neede to conclude on the issue. High wind production in Northern Norway makes a bottleneck to the minor transmission line between North Norway and Finland.

5.2 CO_2 emission reduction

Wind production results in different fuels being replaced in the system. As a combined result of this replacement a CO_2 reduction is achieved. This varies between 680 and 620 gCO_2/kWh in wind1 and wind3 cases respectively. For the 2010 scenario the CO_2 reduction is slightly larger. For comparison, coal, oil and gas fired units emit approximately 800, 650 and 430 gCO_2/kWh respectively.

5.3 Effect on market prices

Simulated spot price for an average inflow situation in the electricity market is about 2.3 eurocents/kWh for today's system. It rises to 3.5 eurocents/kWh for the 2010 scenario due to a CO_2 tax. and reduced power sur-plus (more consumption than production capacity added)

Wind production is seen as extra production in the system with zero marginal price, causing the spot prices on the market to decrease, about 0.2 eurocents/kWh per each 10 TWh/a added wind production (ref2010), little less in ref2000 cases (Fig3). Decrease in spot market price has to do with adding wind power in the market as an extra production. Results of simulations when thermal capacity was decreased while adding wind show only a moderate price decrease (about 0.2 eurocents/kWh per 40 TWh/a added wind production).

5.4 Value of wind energy

The market value of wind energy is the spot market price for the wind production. According to the simulations made here, wind production would be priced on an average about 2 % higher than the spot price. This means that the high price weeks would be slightly more windy than the low price weeks. With large scale wind production in the system (case wind3) this price difference would reduce to about 1 %. Denmark is an exception to this: wind production would be priced 1–2 % lower than the average spot price. Prediction errors in wind production would result in wind producers getting a lower price, when part of the production would be sold in the balance market.

One way of estimating the value of wind energy to the production system is to calculate the avoided costs of thermal power when using wind power. These are the operating costs (mainly fuel costs) of thermal power as well as the fuel saved in electric boilers. The difference in the operating costs of thermal power and electric boilers between the reference case and the wind cases give the avoided costs. For the 2000 system cases the avoided costs by wind power are 2.1 eurocents/kWh in case wind1 decreasing to 2.0 eurocents/kWh in wind3. For the 2010 scenario the avoided costs by wind power are considerably higher than for today’s system, because of the CO_2-tax added to fuel cost as well as reduced power surplus: 3.3…3.1 eurocents/kWh (Fig.3).

Another way of estimating the value of wind energy to the system is to calculate the the socio-economic surplus (sum of consumer and producer surplus, Fig 2). When looking at the differences in the socio-economic surplus between reference and wind cases, we get the value of wind to the whole market. For the 2000 system cases this is 2.4 eurocents/kWh decreasing to 2.0 eurocents/kWh with large scale wind production. For 2010 scenario the total value of wind production to the system is 4.4…3.9 eurocents/kWh respectively (Fig. 3).

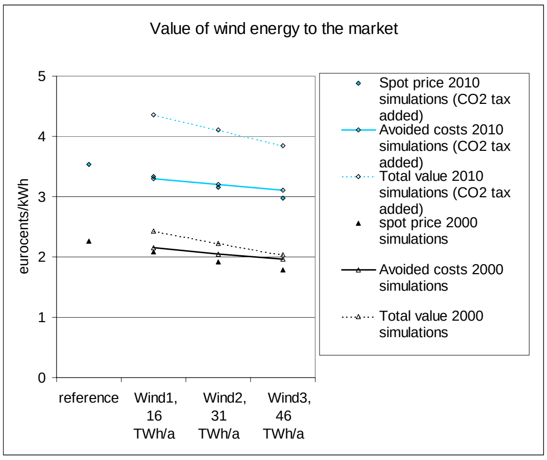

Figure 3: Avoided costs and socio-economic surplus (total value) when comparing the wind cases to the reference cases. For comparison, the average spot price (South-Norway) is shown. (All prices for an average hydro inflow.)

6 CONCLUSIONS AND DISCUSSION

The Nordic electricity market has been simulated with and without wind production to assess the effects of large scale wind production on the market. Results of weekly electricity flow and prices in the market area for different hydrological years can be obtained from the EMPS power market simulation model output.

Wind power replaces mostly coal condense and oil as fuel for electric boilers. For large amounts of wind power, 8–12 % of consumption, also nuclear production is slightly reduced during wet years. Reductions do not occur in the same countries as the wind production, f.ex. coal condense is replaced also in Central Europe. As a result of adding wind to the simulated system, CO_2 emissions will be reduced 680…620 gCO_2/kWh.

Indications for bottlenecks in transmission can be seen, especially to Central Europe, when wind production is above 8 % of the electricity consumption.

Large amounts of wind production in the market will lower the spot price, when wind production comes as an extra production to the system. Average spot market price drops by roughly 0.2 eurocents per 10 TWh/a wind production added to the system. Wind power would get on the average 1–2 % higher price than the spot price, if no prediction error is taken into account. Comparing the market spot prices with total production costs for wind power, it is clear that today's market price would not be enough to initiate investments in wind power, where as market prices as a result of our scenario for 2010 would make the best wind resource sites cost-effective.

Avoided costs for wind power production are 2.0…2.1 eurocents/kWh when adding wind production to today's system, slightly higher than average spot price. This is not taking into account any environmental benefits of wind production. CO_2 tax added to fuels of conventional power brings an environmental bonus to wind power in the 2010 figures, where the avoided costs would be 3.1…3.3 eurocents/kWh. The avoided costs give the value of wind to the total production system, as the reduced operational costs for electricity production.

The socio-economic surplus to the electricity system takes into account both the consumer and producer sides of the market. The socio-economic value of wind energy for the system is 15 % higher than average spot price for today's system and 30 % higher than the average spot price for the 2010 scenario with CO_2 tax and reduced power surplus in the system (more consumption than production added). The socio-economic value is what a market regulator would look into, when analysing whether wind production would be beneficial for the system, and how much wind could be subsidised from themarket point of view.

These conclusions are made from simulations assuming that all the large scale wind production will be available in the system. This means that grid connection as well as the hourly variations of wind would be taken care of. Weekly and hourly scheduling of thermal and hydro power with large wind production share will be questions for further study.

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The effect of wind power on CO_2 abatement in the Nordic Countries

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Abstract

Simulations with the power market model EMPS and the energy system model EFOM have been made to assess the effects of large-scale wind production on the CO_2 abatement in the Nordic countries. We are mostly focusing on the year 2010, comparing the results with substantial wind power amounts to a base case scenario. The results for the EMPS simulations with 16–46 TWh/a wind production in Nordic countries (4–12% of electricity consumption), show that wind power replaces mostly coal-fired power generation. As a result of all fuels replaced by wind production a CO_2 reduction is achieved, of 700–620 g CO_2/kWh. The results for the simulations of Finnish energy system show similarly that new wind power capacity replaces mainly coal-fired generation. In another scenario it has been assumed that the use of coal-fired generation is prohibited in order to meet the Finnish Kyoto target. In this case new wind power capacity would replace mainly natural gas combined-cycle capacity in separate electricity production and the average CO_2 reduction would be about 300 g CO_2/kWh. This case reflects the situation in the future, when there is possibly no more coal to be replaced.

Keywords: Wind power; CO_2 abatement; Energy system modeling

1. Introduction

The purpose of the paper is to study the influence of large amounts of wind production on the CO_2 abatement of the energy sector. This is a relevant question for national policy makers when estimating the costs of CO_2 abatement, for example when comparing different measures.

The electricity supplied by wind power is free from CO_2—even taking into account the materials and construction of wind farms, the CO_2 emissions are of the order of 10 g CO_2/kWh wind power produced (Lenzen and Munksgaard, 2002). When wind energy is replacing production forms that emit CO_2, the CO_2 emissions from the electricity system are lowered. The amount of CO_2 that will be abated depends on what production type and fuel is replaced when wind power is produced.

In both regulated and deregulated electricity systems, the production form in use at each hour that has the highest marginal costs, will be lowered due to wind energy. It usually means the production of old coal fired plants, resulting in a CO_2 abatement of wind energy of about 800–900 g CO_2/kWh. This is often cited as the CO_2 abatement of wind energy (e.g. EWEA, 1996).

This is true for most systems with some coal fired production plants, when wind energy provides a minor amount of total electricity consumption. It is a good estimate for the CO_2 effects for the first national targets, when first introducing wind power to a country.

This is also true for large amounts of wind, for the countries that have electricity production mostly from coal. For other countries, the situation may change when adding large amounts of wind power to the system. There might not exist old coal plant capacity for the whole wind power production to be replaced at all times of the year. During some hours of the year, wind would be replacing other production forms, like gas fired production (CO_2 emissions of gas are 400–600 g CO_2/kWh), or even CO_2 free production forms, like hydro, biomass or nuclear power.

Sometimes estimations of CO_2 abatement are done using the average emissions of electricity sector. In countries with a large share of renewables and nuclear power, this decreases the benefits of wind power considerably compared with the estimates using 800–900 g CO_2/kWh as the abatement measure.

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Some studies have taken the long-term replacement of wind power as a starting point, when wind power is replacing other new investments (IEA GHG, 2000). If wind power is considered as an alternative to another new capacity, like gas fired plants, then the CO_2 abatement of wind is cited as the avoided emissions of the alternative. That becomes 300–400 g/kWh when looking at future natural gas combined-cycle capacity (IEA GHG, 2000). When looking at the situation today, this way of studying the abatement of wind power neglects the initial CO_2 abatement of the gas plant to the system. This actually reflects the situation in the future, when there is no more coal to be replaced, but the replacement will be gas.

When there are large hydro reservoirs in the system, it is not enough to look at the instantaneous response of the electricity system to some hours of high wind power production: even if the hydro production is reduced instantaneously, the hydro power stored in the reservoirs will be produced at a later instant, reducing fossil fuel fired production at a later time. This is why it would be unusual for wind power to replace hydro power, unless the system is hydro dominated. Interconnected systems can also respond in a way that wind power is partly replacing coal fired production in a neighbouring country.

All this means, that when the electricity system is not consisting mainly of coal fired units, and we are talking about large-scale wind power production, it has to be simulated what would happen in the system when adding wind. Comparing the results of simulations with and without wind capacity will give us the CO_2 abatement of wind. There are not many studies made like that so far, but some examples exist already. In a previous study for the hydro-thermal system of Finland (Peltola and Petäjä, 1993), a probabilistic production cost simulation model was used. Producing 1–6% of yearly electricity consumption with wind power, while maintaining the same reliability of the electricity system, resulted in CO_2 emission savings of 900 g CO_2/kWh. For the Egyptian hydro-thermal system, simulations show a CO_2 reduction of 640 g CO_2/kWh wind (El-Sayed, 2002).

In the Nordic countries, the electricity system is characterised by large share of hydro power. There are long traditions in operating the system according to the varying hydrological years: electricity is exported from Norway and Sweden to Finland and Denmark during wet years, and electricity is exported from the thermal plants of Finland and Denmark to Sweden and Norway during dry years. The deregulated electricity market in the countries has led to the joint electricity market Nordpool. The benefits of wind power reducing the CO_2 emissions can result in different countries of the joint electricity system than where the wind power is built. It is therefore relevant to look at the whole Nordic system for CO_2 emissions with and without wind power. Wind power is still marginal in the system today (4 TWh/a mainly in Denmark). National targets exist for 16 TWh/a in 2010 (Denmark 8, Sweden 4, Norway 3, Finland 1 TWh/a), and considerably more in 2030.

In this paper, the effect of wind power production on CO_2 abatement is simulated in two ways. By running simulations on the EFI's Multi-Area Power Market Simulator (EMPS) model for the whole of the Nordic electricity market, we get the effects of wind power to the dispatch of other production units in the interconnected Nordic electricity system, for an average, wet and dry year. These simulations are based on electricity market operation with a fixed power production capacity, taking into account the operating costs of each power production form only. By running EFOM for the Finnish energy system we get the effects of wind power to one country, taking into account also capacity expansion during a longer time period.

2. Simulations with EMPS model for the Nordic area

2.1. Description of the model

The power market model EMPS is a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting (Flatabø et al., 1998; Sintef, 2001). EMPS simulates the whole of the Nordic market area. The market is divided into areas with transmission capacities between the areas (Fig. 1). Central Europe is modelled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities. The simulation is here made for 1 year, with weekly time steps. The model simulates the market price, production and export/import for each area. The running/dispatch of the production units is simulated, and the system with the firm consumption pattern and production system are static. This means that new investments to production capacity, changing fuel prices or increasing demand are all changes that must be treated with a new system definition and a new simulation.

We are using 2 systems for the base case: electricity system for year 2000 and a scenario for year 2010. Wind is added to these systems step-by-step, in order to study the incremental effects of wind power on the system.

Electricity consumption and production capacities are modeled for each area, as well as the transmission lines between the areas. The production capacity is shown in Table 1 for both the 2000 and 2010 base case. The thermal capacity is given either as a maximum capacity (MW) or a maximum weekly production (GWh). The electricity consumption contains price elastic demand, mainly in Norway and Sweden. This is provided by

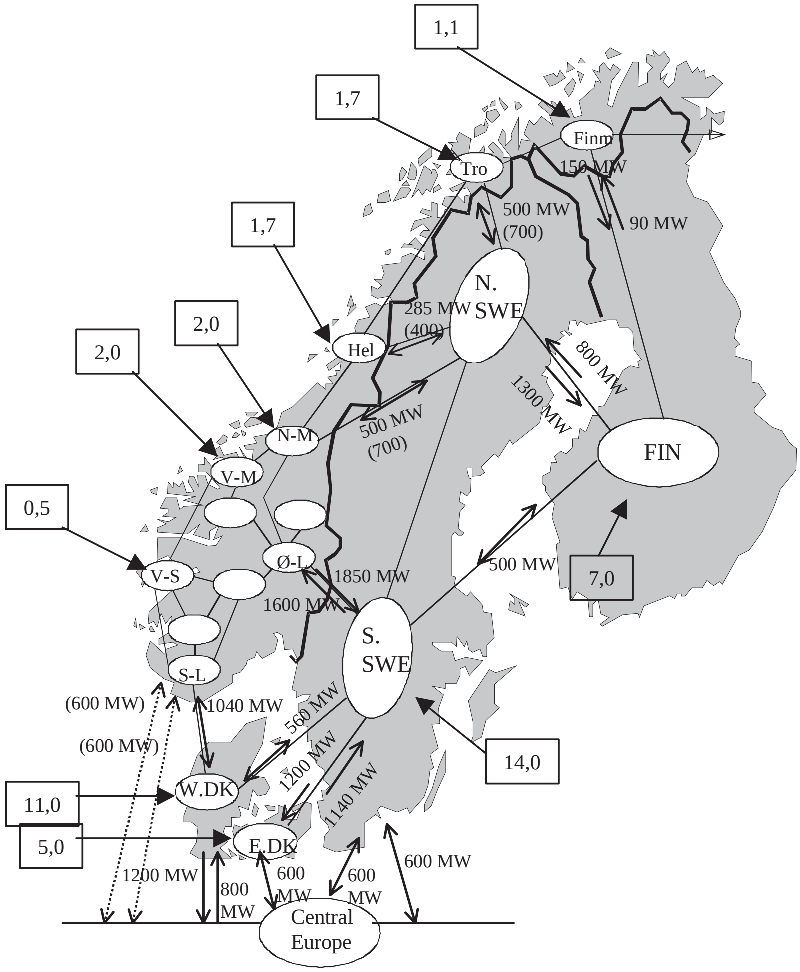

Fig. 1. Areas and transmission capacities between the countries (scenario 2010 figures in parenthesis) and wind3 amounts of wind production (TWh/a) in the EMPS model.

electric boilers, which can switch from burning oil to using electricity, and also industrial consumption in Norway. The capacities for transmission lines are shown in Fig. 1. Between Norway and Sweden lower limits for the lines than in (Nordel, 2001) are used in order to take into account the technical restrictions of transmission.

Operating costs for the production determine the market price at each simulated time step. This is because we are simulating the bidding process in the market. In the market the producer gets the price determined by the market cross (Fig. 2), thus it is cost-effective for him to produce as long as the price he gets is higher than his variable costs. Input values for the operating costs are presented in Table 2. It is not possible to acquire the cost data anywhere, as it is confidential information for the market actors. The assumptions in Table 2 are based on fuel prices and the running of the model against the Nordel production statistics—as our simulation produces similar production and exchange amounts as seen in the statistics, we can suppose that our cost input for the reference year 2000 is reasonable. Wind energy is a price taker in the market: all that is produced will be sold, no matter what price. The marginal price is therefore 0 Euro/MWh for wind, when operating without storage, like it is for run-of-river hydro plants. Assuming zero marginal cost for wind power is common convention, even if this is not strictly true, as some of the operation and maintenance costs would be lowered if the plants were shut down.

The main substance of the model is the detailed optimisation of the hydro system. The hydro power producers try to save the water in the reservoirs to the critical times of high consumption during the winter, when they get the best price for their production—and also when the system needs all the power available to cover the load. To determine the way that the limited amount of water in the reservoirs can be used most cost-effectively, the value for stored water is calculated. These so-called water values vary both by the time of year and by the current and anticipated water inflow to the reservoirs. Water values are calculated by a

Table 1
Maximum production capacity and electricity consumption as input to the EMPS model (ref2000 plain ref2010 bold)

	Finland	Sweden	Denmark[a]	Norway	Central Europe[b]
Consumption (GWh/a)	78,800	142,400	34,900	120,000	567,100
	90,500	**152,300**	**37,000**	**121,900**	**567,100**
Nuclear (GWh/a)	21,800	70,800			21,813
	21,800	**67,000**			**21,813**
CHP (GWh/a)	24,800	8741	8000		
	28,600	**15,000**	**7300**		
Condense[c] coal/oil (MW)	4132	435	5967	280	69,421
	3157	**435**	**2900**	**280**	**69,421**
Condense[c] gas (MW)	167		815		14,661
	167		**2320**	**400**	**14,661**
Condense[c] other (MW)	366				600
	691				**600**
Gas turbines (MW)	975	195	70		
Hydro[d] (GWh/a)	13,000	63,000	3500	115,000	

CHP = Combined heat and power.
[a] Denmark: part of condense used with heat load. Modelled as max 1840 MW + max 27,000 GWh/a in 2000, max 2500 MW + max 27,000 GWh/a in 2010.
[b] Central Europe: condense power modelled as max 40,970 MW + max 196,000 GWh/a.
[c] In this paper the terms "condense" and "condensing power" refer to all thermal power plants (excl. nuclear power) that are producing electricity only. This terminology is needed in order to make a clear distinction between power plants and combined heat and power (CHP) plants.
[d] Average for 30 years. Wind in DK.

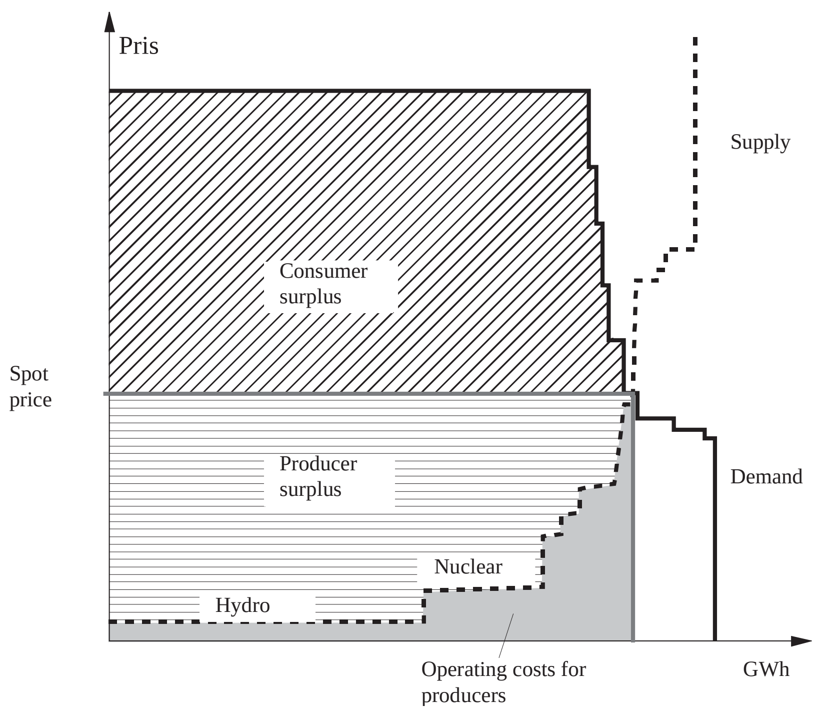

Fig. 2. Market cross: the spot price calculation in the power market simulation model EMPS.

stochastic dynamic programming algorithm, maximising the value of hydro production (Flatabø et al., 1998).

With the demand and a price for each production capacity known, the market price is determined by a market cross (Fig. 2). Operating costs given as input values are used for thermal production. Water values are the prices used for hydro plants with reservoirs when calculating the producer curve in Fig. 2. Demand and production curves are simulated for each week, and four load duration levels are used to take into account the consumption pattern (high/low) inside a week. Technical availability of thermal capacity is taken into account in the simulation, when composing the production/price curve for each time step (Fig. 2). If transmission

Table 2
Operating costs for power production as input to the EMPS model (ref2000 plain ref2010 bold)

	Finland	Sweden	Denmark[a]	Norway	Central Europe
Nuclear	8.7	8.7			8.1
CHP[a]	6.2	6.9–21.2	0.0		16.8
		6.9–23.7	**0.0**		**28.7**
Condense coal/oil	16.7	31.2	13.4–20.7	12.48–56.2	8.1–39.3
	27.5–32.4	**31.2–42.4**	**28.1–31.2**	**13.7–82.4**	**24.1–45.1**
Condense gas	32.0		19.3–26.1		18.7–31.2
	28.7		**26.5–27.1**		**26.2–32.4**
Condense other	32.2				
	27.5				
Gas turbines	52.4	52.4	44.3		
	60.3	**67.9**			

CHP = Combined heat and power.
[a] The Danish prioritised, decentral CHP production is modelled as 0 costs.

capacity is restricted, there will be different prices in different areas, so basically the model simulates how the Nordpool market operates.

Because the EMPS model is run with a static production capacity given as input, for year 2010 a new input based on a scenario was made. Electric consumption was added by 32.2 TWh/a in the Nordic countries, and production capacities were changed (MTI, 2000). For Sweden one nuclear plant was shut down, fossil fuel fired condensing power was shifted to biofuels and CHP was added. For Finland more CHP and coal was added (MTI, 2001a). For Norway a new gas-fired power plant (400 MW) was added. For Denmark coal was shifted towards gas (Energy 21, 1996). Improved transmission capacity was foreseen for Norway/Central Europe and between Norway and Sweden (Fig. 2). CO_2 tax of 15.6 Euro/t CO_2 was added to operating costs of fossil fuels. The effect of CO_2 tax is to rise the marginal costs: for coal by roughly 12.5 and gas by 7.5 Euro/MWh. Thermal power costs in Central Europe were adjusted closer to those in Denmark and Finland to reach a balance in the market. As a result from changing the system from today's system to a 2010 scenario, the simulated thermal production for 2010 was up by 25.4 TWh/a and price elastic demand (dual fueled boilers, and industrial consumption in Norway) was down by 5.7 TWh/a.

The model calculates the emissions produced, by simply multiplying each produced kWh with an emission factor specified for that production type. These emission factors are also an input to the model. Because the production units are grouped to larger groups, where both the efficiency and sometimes part of the fuel input can vary, these emission factors have to be roughly estimated. Biomass, nuclear, hydro and wind production are taken as CO_2 free production forms. We have used 790–1120 g CO_2/kWh for coal and coal/oil fired plants; most of the production in Denmark and Finland comes from a range of 800–880 g/kWh, and the plants in Germany are assumed to emit 1025 g/kWh. For gas fired production, emission factors used range between 450 and 520 g CO_2/kWh. For the combined heat and power production, there is the problem of dividing the emissions between the electricity and heat produced, as we are here only simulating the electricity production. Case studies from Finnish CHP plants suggests that this allocation could be 25–65% for electricity production (Mayerhofer et al., 1997), depending on the technology and allocation principle. We have used a rough estimate of dividing the emissions half and half to electricity and heat. This assumption does not have a notable impact on the results in these simulations, however, as the CHP electricity production is mostly assumed as a by-product of heat demand, bid into the markets with low price and therefore not being replaced by wind power added to the system. In today's system CHP emission factors are only used in Finland and Sweden, for 2010 partly in Denmark also. In Denmark, extraction CHP is used and CHP is operated shifting from condense production to different levels of combined production, which means that also the emissions will be partly like from condense power plants.

As we are looking at what production form wind power would replace, the most important input values to the simulations are the ones determining which production is running at the margin. This is the cost (and amount) input for the conventional production units in the system. For our simulations, looking at Table 2, nuclear and CHP production is bid to the market at a low price, and therefore it will be the condensing power that will first be affected by wind power added to the system.

2.2. Simulation of wind power production

Wind power was added to the system in 3 phases, cases wind1–wind3, starting from 16 TWh/a (wind1) to reach 46 TWh/a (wind3) annual total production in the Nordic countries. This corresponds to 4–12% of total electricity consumption, and it is divided between the countries as 20–45% of consumption in Denmark and 2–10% of consumption in Sweden, Norway and Finland (Table 3). Wind1 corresponds to existing targets for 2010 and wind3 is near possible targets for 2030.

The model takes into account the different inflow and varying wind situations by using historical inflow and wind data from 30 years as input for the simulation. The results of the simulation are shown as average values, with the minimum and maximum values yielded each week for different inflow situations (dry and wet years). It is also possible to look at the results for a specific inflow year (i.e. examples for a wet and dry year).

Weekly wind production was calculated from wind measurement data (Tande and Vogstad, 1999). The total weekly wind power production, in wind3 simulation, as an average over 30 years, as well as the 30-year-minimum and -maximum weekly values can be seen in Fig. 3.

Table 3
Wind power added to the system. Production in TWh/a and as % of electricity consumption today in the simulated cases

	Wind1		Wind2		Wind3	
	TWh/a	%	TWh/a	%	TWh/a	%
Norway	3	2.5	6	5.0	9	7.5
Sweden	4	2.8	9	6.3	14	9.9
Finland	1	1.3	4	5.1	7	8.9
Denmark	8	22.9	12	34.3	16	45.7
Total	16	4.3	31	8.2	46	12.2

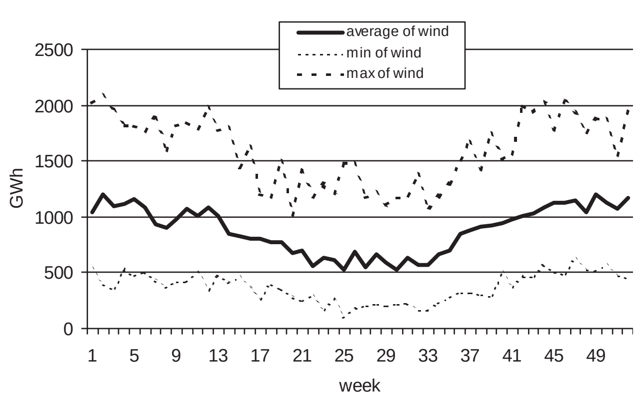

Fig. 3. Input for wind power production for the simulation (wind3, 46 TWh/a). The combined wind power production of all countries is presented as weekly average, maximum and minimum production from 30 years of data.

In Norway, wind power was added to 6 areas, based on 3 wind measurement data points in Middle and North Norway. Wind power was added to South-Sweden based on 3 wind measurement data points in Southern Sweden and Gotland. Wind power was added to both areas in Denmark, some more to West Denmark than to East Denmark. From Denmark only one measured wind speed series was available (Vogstad et al., 2000).

Large-scale wind production would in reality mean production from many, scattered wind parks. Using data for few, single measurement points will over-estimate the variations of wind production in a large area. As we are using weekly averages, however, this overestimation is not as profound as it would be in, e.g. hourly data.

Wind production is only weakly correlated between the countries. Yearly wind and hydro production are not correlated, that is, the correlation coefficients for the yearly time series are near 0. This means that wet years are not likely to be good wind years—but are not likely to be bad wind years either, all combinations will occur.

Wind power is modelled as a run-of-river hydro plant: wind energy is the inflow to a plant, which has no reservoir, or flood, which means that all that comes as inflow will be produced. No prediction method for wind is used, but the stochasticity of wind will be taken into account in the dynamic programming phase: when calculating the water values for the stored hydro reservoirs, the probability of future wind production will affect the values the same way as the part of the inflow that flows through the hydro plants without possibilities to store the water.

2.3. Results of the EMPS simulations

Wind power will replace the production form that has the highest marginal costs: wind will come to the production curve in Fig. 2 from the left (0 Euro/MWh) and shift the curve to right resulting in some of the production near the market cross to be replaced. As the consumption and production curves will be different for each week, also the production form that wind will replace will differ. If we had a system with abundant coal condensing power production we could say that it will always be coal that wind is replacing. In the Nordic system, with a lot of hydro and nuclear production, as well as CHP produced according to heat demand, it has been simulated week by week to see the result.

The results from wind1 scenario, where there is a total of 16 TWh/a wind power production, compared with the base case scenario (with Danish 3.5 TWh/a wind), summed up from all countries, is as follows: adding 12.5 TWh/a wind to the system will reduce 8.5 TWh/a coal, 1.8 TWh/a gas, 1.4 TWh/a oil and 0.2 TWh/a peat power production. There will be also minor decreases in biomass and nuclear production, as well as a minor increase in hydro production, all less than 0.1 TWh/a.

Large amounts of wind, 42.5 TWh/a added wind (46 TWh/a total) will replace 28.9 TWh/a coal, 7.2 TWh gas, 3.7 TWh/a oil as well as 0.5 TWh/a peat, 0.3 TWh/a biomass and 0.2 TWh/a nuclear power production. Hydro power will be decreased by 0.2 TWh/a, due to increased floods in springtime coincident with high winds. The replacements do not amount to exactly same amount as wind power added to the system, because slight changes in electricity consumption will occur. Also the transmission losses increase, which can be seen in the wind3 simulation (0.1 TWh/a increased transmission losses between the areas).

In more detail, looking at each country, an example of the simulation results is presented for Finland, in Fig. 4, summed up by production forms. In Finland, wind production replaces condensing power production (mainly coal). Electricity imports to Finland increase. For wet years in the wind3 case (7 TWh/a in Finland

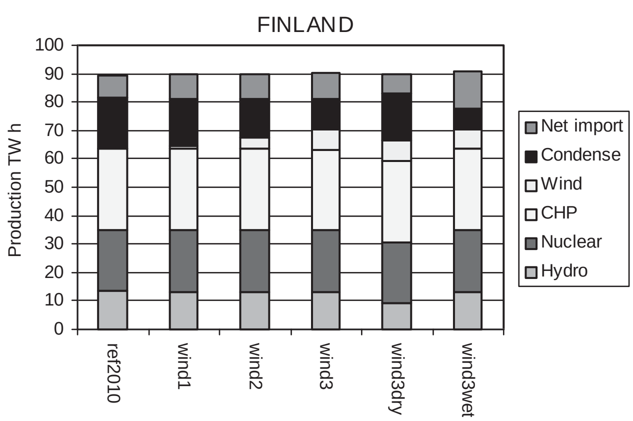

Fig. 4. Production and net import in Finland: reference and wind1–3 simulations for the system in 2010. In addition to the 30-inflow-case-average results, also example years for wet and dry years are presented, for wind3 case (the year of the largest inflow in the Nordic countries was not specifically wet in Finland).

and 46 TWh/a in Scandinavia) the nuclear production is slightly reduced.

In Sweden, the electricity consumption in electric boilers is increased with increased wind production. This means that wind production is replacing oil (alternative fuel for the boilers). Wind production is replacing condensing power production, for the little there is to replace, and some of the nuclear and CHP production will be decreased. Export of electricity is increased substantially.

In Norway the consumption in electric boilers increases with added wind production. Export is also increased.

In Denmark, wind is replacing condensing power (mainly coal) and increasing exports. Both imports and exports in Denmark are increasing with increasing wind in the system.

As wind production is added as extra production to the electricity system, about 40% of the wind production is transferred out of the Nordic countries with the transmission lines to Germany, Poland and the Netherlands (in the scenario for today's system about 30%).

The yearly CO_2 emissions of the simulated cases are presented in Fig. 5. This is the model output, calculated from simulation results of produced electricity from different production forms and the emission factors given as input. The effect of electricity replacing oil used in boilers (price flexible consumption) is to lower the emissions, this is also taken into account in the emissions shown in Fig. 5.

The result of the wind1 simulation, adding the amount of wind foreseen in 2010, is that as a combined result of different fuels being replaced in the Nordic system, a CO_2 reduction of wind power is 700 g CO_2/kWh: CO_2 reduction 8.7 Mt when adding 12.5 TWh/a wind power to the system. Adding more wind results in somewhat lowered emission reductions: 650 g CO_2/kWh in wind3 case, CO_2 reduction 28.8 Mt when adding 42.5 TWh/a wind power to the system. For the 2000 scenario the CO_2 reduction is slightly smaller, 680–620 g CO_2/kWh.

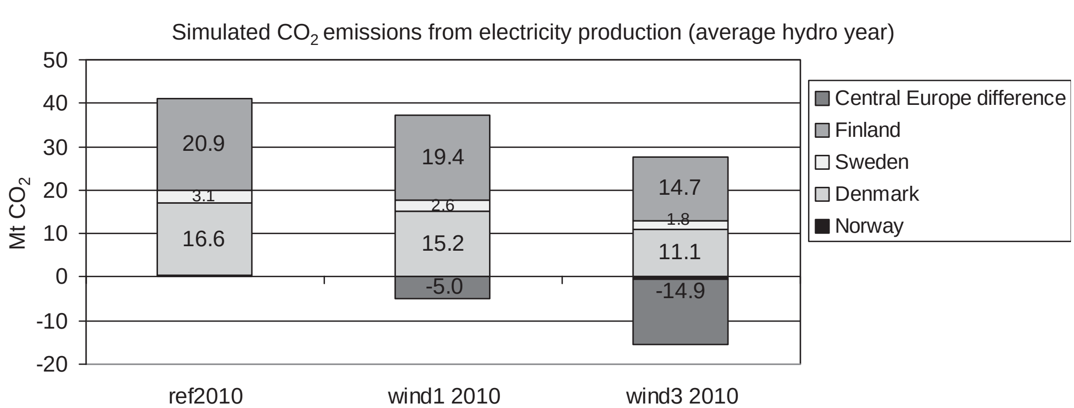

Fig. 5. CO_2 emissions in reference, wind1 and wind3 simulations for an average hydro year.

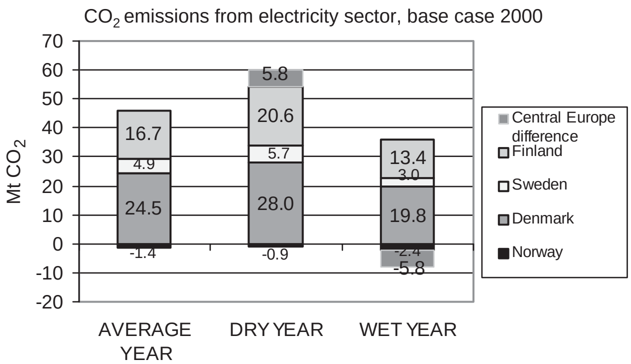

Fig. 6. CO_2 emissions of electricity production in reference simulation for year 2000. In addition to the 30-inflow-case-average results, also example years for wet and dry years are presented.

It is notable that the wind production added to Norway and Sweden will mostly replace thermal power produced in Finland, Denmark and Central Europe. This is a result of having an interconnected system with a common electricity market: the system covers the whole of the area and thus power will be replaced where it is most cost effective. The hydro power in Norway and Sweden will not be replaced even with substantial wind production, as long as there are possibilities to increase the exports to other countries.

It is also notable how much the emissions of electricity sector differ yearly depending on how much CO_2 free hydro is available to the system. The difference is $\pm$ 6 Mt for Central Europe, $\pm$ 5 Mt for Denmark, $\pm$4 Mt for Finland, $\pm$2 Mt for Sweden and $\pm$1 Mt for Norway (Fig. 6). This reflects the way the Nordic system is operated: during wet years the hydro production is exported from Norway and Sweden and during dry years these countries import thermal power from Denmark, Finland, and Central Europe.

3. Simulations of the EFOM model for Finland

3.1. Description of the model

The EFOM model is a quasi-dynamic many-period linear optimisation model. It has been widely used to analyse national energy systems and mitigation of greenhouse gas (GHG) emissions (e.g. Lueth et al., 1997; Lehtilä and Pirilä, 1996). Another widely used model of this kind is MARKAL (e.g. Kram and Hill, 1996). More advanced similar kind of models (e.g. TIMES) are being developed under the IEA ETSAP agreement (IEA, 2002).

In EFOM the whole system is represented as a network of energy or material chains. The network of the described energy system starts from the primary energy supply and ends in the consumption sectors. EFOM is a bottom-up model and it is driven by an exogenous demand for useful or final energy in the consumption sectors. The Finnish EFOM model includes descriptions of other activities that emit greenhouse gases (e.g. waste management and agriculture) and due to national characteristics also detailed subsystems for e.g. domestic fuel supply, pulp and paper industry, and combined heat and power production. The system is optimised by linear programming using the total present value costs of the entire system over the whole study period as the objective function which is to be minimised. The whole study period is divided into sub-periods, which can be of different length. In this study the period is 2000–2025 and the time step is 5 years. The year is divided into winter and summer seasons and therefore the seasonal changes, e.g. in wind and hydro power production can be taken into account. The solution includes the statistics of all model variables for the end of each sub-period (Lehtilä and Pirilä, 1996; Tuhkanen et al., 1999).

EFOM includes wide range of descriptions of both present and new energy production and consumption technologies. Main inputs of the EFOM model are scenarios for final or useful energy in the consumption sectors, scenarios for characteristics of the technologies, and many constraints for, e.g. availability of different energy sources. The most important input concerning this study is the development of the costs of different energy production technologies including investment, fixed, and variable costs. The costs will greatly determine which electricity production technology is used or built less when more wind power is added to the system.

In EFOM the GHG emissions from the energy system are calculated directly by multiplying the annual fuel use with the corresponding emission factor. The factors are mainly based on IPCC (1997) and they are similar to the ones used in the Finnish National Greenhouse Gas Inventory. This methodolody is applied to all energy production and other fuel consumption in the model, i.e. power production, CHP, heat production, transport etc. Emission limits, e.g. for total national GHG emissions can be used as a constraint for the optimisation of the energy system.

3.2. Description of the scenarios

The effect of incremental wind power in the Finnish electricity system on CO_2 emissions has been studied by comparing different wind power production levels in two different scenarios: "Baseline" and "Kyoto" up to the year 2025. The only difference between these scenarios is the target for national GHG emissions. In the Baseline scenario no emission reduction targets were set on greenhouse gas (GHG) emissions (i.e. Business-as-Usual scenario), and the development of the energy system is dependent mainly on the costs. In the Kyoto

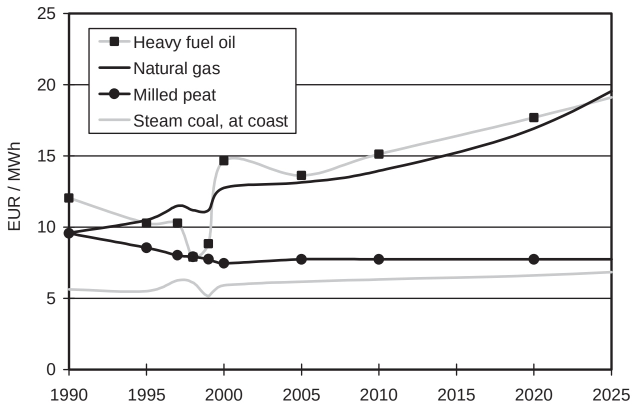

Fig. 7. Trends in main fuel prices in Finland in 2000 prices excluding taxes.

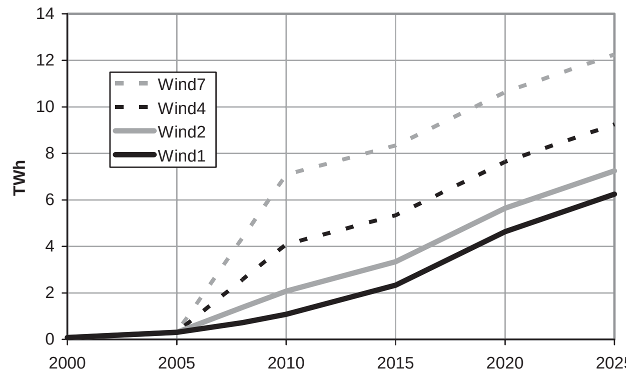

Fig. 8. Assumed development of wind power production in Finland in different cases.

scenario the GHG emissions have to be stabilised to the 1990 level according to the Finland's national Kyoto target. In this case it has been assumed that the use of coal power is nearly prohibited among other measures in order to reach the GHG target. These two scenarios lead to different kind of capacity extension and, consequently, to different CO_2 abatement of wind power.

Fuel prices in the scenarios are of central importance. The assumed trends in main fuel prices in Finland are presented in Fig. 7. The trends for imported fossil fuels are based on IEA World Energy Outlook (2000) with some adjustments due to different characteristics of national fuel supply. The trend for peat fuel is based on national expert judgement.

Especially the significant increase in natural gas price affects the development of electricity supply. In the Baseline scenario it leads to significant extension of coal-condensing power capacity due to its better competitiveness when compared to gas-fired capacity. Both natural gas consumption and the dependency on Russian gas exports in the European Union are expected to increase significantly (European Commission, 2000) which leads most probably to higher price levels in the future. The developments of other costs of different energy technologies included in the model are based on numerous national and international studies and expert judgements.

Nuclear power production starts to decrease gradually around 2020 in both scenarios, and new capacity is not allowed. Hydro power capacity increases slightly during the study period, mainly due to renovations and new small-scale capacity. Maximum electricity imports are set to about 6 TWh/a. The background of the scenarios is described in more detail in Kara et al. (2001). The input data in these scenarios are mainly similar to data used in the scenarios in the Finnish Climate Strategy (MTI, 2001a, b).

Both scenarios were calculated at first by letting the model find the optimal development of energy production mix. Thereafter fixed scenarios for wind power production have been added to EFOM to study the effects of increased wind power production on the energy system and CO_2 emissions. These scenarios were chosen to be consistent with production levels for Finland in the EMPS simulations, i.e. 1, 4 and 7 TWh/a in 2010 (see Table 3). In addition, a scenario in which a level of 2 TWh/a would be reached in 2010 was studied. The development of wind power production in these fixed cases is presented in Fig. 8. In the simulations with fixed wind power scenarios, the EFOM model finds a new optimum for the development of the whole energy system.

In these scenarios most of the new wind power capacity is assumed to be offshore because different factors (e.g. poor wind conditions, land use restrictions, etc.) restrict large-scale wind power production in land areas in Finland. Onshore production is limited to about 2 TWh/a in 2010 and about 3 TWh/a in 2025. Offshore production is, however, more expensive despite the fact that wind conditions are much better. It is assumed to be commercial in Finland after 2005. Estimated development of wind power production costs is shown in Fig. 9. Average full load hours for wind power have been used: 2200 h/a for onshore and 3000 h/a for offshore wind power. Lifetime of 20 years has been assumed for wind power plants and 5% discount rate is used by the model to all power sector investments. This is quite common assumption for discount rate in the energy system analyses.

3.3. *Results*

In the Baseline scenario, wind power production remains quite low throughout the period as can be seen in Fig. 10. In these fixed wind power scenarios (Base-Wind1, etc.), the incremental wind power replaces mainly coal-condensing power. Also small reductions in district heat and power production can be observed, especially in the use of natural gas combined cycle capacity. However, these reductions are typically only

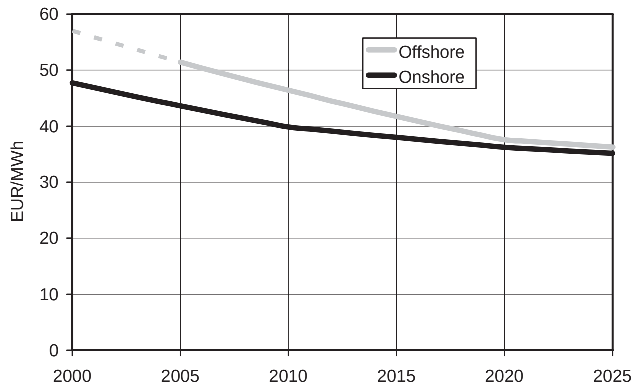

Fig. 9. Estimated production costs for new wind power plant in Finland in 2000 prices.

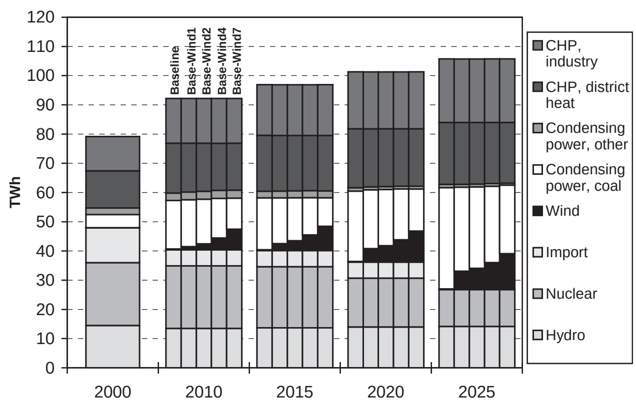

Fig. 10. Total electricity supply in the Baseline scenario with different wind power production levels.

some hundreds gigawatt-hours electricity annually. If all CO_2 emission reductions in the energy system were allocated to incremental wind power production, the GHG emissions will be reduced on the average about 680–700 g CO_2/kWh during the period 2010–2025 in all cases. The emission levels of other GHGs than CO_2 remain practically stable despite of the changes in the electricity production mix.

Carbon dioxide emissions from the energy system will decrease quite significantly at least in the end of the period in all cases. In 2010 the total CO_2 emissions would be about 1–6% lower and in 2025 about 5–11% lower than in the Baseline scenario.

CO_2 abatement costs for wind power have been estimated by comparing the annual costs of the whole energy systems in different cases, in relation to CO_2 emissions in each case. For Base-Wind1 scenario the average emission reduction costs during 2010–2025 seem to be about 20 €/t CO_2. When the wind power capacity is further increased the average costs will rise gradually to about 35 €/t CO2. This is quite obvious result because at first wind power replaces the most expensive condensing power capacity and after that the replacement is aimed at less expensive capacity (see e.g. supply curve in Fig. 2) and, therefore, the emission reduction per unit wind power generation becomes more expensive.

In the Kyoto scenario, wind power capacity increases quite remarkably in the cost-optimal case due to its competitiveness as an emission reduction measure. As mentioned earlier the use of coal-condensing power is minimised in this scenario in order to reach the Kyoto target for GHG emissions. Consequently, when more wind power is added to the energy system, the new capacity replaces mainly other condensing power capacity which is in this case natural gas combined-cycle (NGCC) capacity. In district heat and power sector minor changes would occur in the production level and the fuel mix, but a clear replacement of certain technology cannot be observed. The specific CO_2 emission reduction is only about 260–300 g CO_2/kWh due to the high efficiency of NGCC and other small changes in the energy system. It should be noticed that in the Kyoto scenarios the average CO_2 emission from electricity production is much lower than in the Baseline scenarios, and consequently the achievable emission reduction are clearly lower. Also, part of the wind power potential would be used already in the basic cost-optimal case, against which the wind cases are compared, and so this is the result of increased wind production to the system. Increased wind power production also seems to increase slightly the total electricity supply. In other words some energy saving measures would not be implemented when wind power production is extensively increased. This is due to the nature of the model: it will calculate a new optimum for the development of the whole energy system every time a slight change is implemented, and therefore surprising changes might occur. In realworld the energy saving

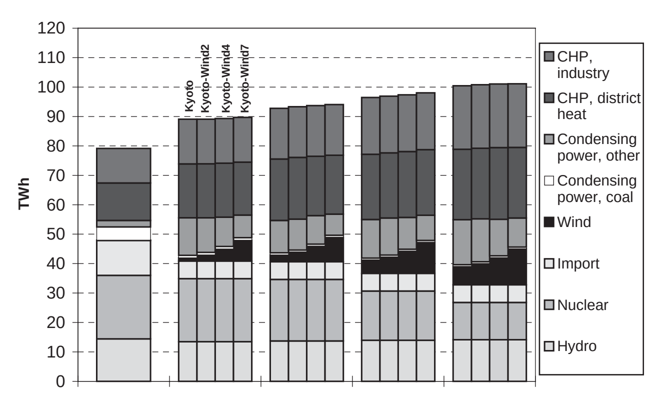

Fig. 11. Total electricity supply in the Kyoto scenario with different wind power production levels. Wind1 scenario is not shown here because the wind power production is nearly the same as in the cost-optimal Kyoto scenario.

measures would hardly compete with wind power. The development of the electricity supply in the Kyoto scenarios is as shown in Fig. 11.

The achievable emission reductions are significantly lower in the Kyoto scenarios and therefore the specific emission reduction costs increase to about 40–60 €/t CO_2.

4. Comparison of the results and discussion

Two different simulation models for the energy system have been used to assess the CO_2 abatement of wind power in Finland and the Nordic countries. An overview of the simulated cases is presented in Table 4.

These models are not designed for solving this kind of problems in particular. The main usage of EMPS is simulating the market price taking into account the large hydro power share in the market, and scheduling the hydro power production from the large reservoirs in an optimal way. The strength in EMPS is that it can simulate the running of different production units, like it is operating today, as a large, interconnected area. Therefore it is able to simulate a large amount of different situations, with 30 years of inflow and wind power data, and look into detail in what wind power will replace in a hydro-thermal system during different weeks, with high and low load situations. The weakness of EMPS is that the longer term picture is difficult to form: the system is fixed for each simulation, not allowing capacity expansion. It is not an easy task to formulate future scenarios of the whole Nordic system as an input, making sure that the system operates in a balanced way. Correspondingly, EFOM is mainly used in long-term energy and environmental policy support studies in national level. In the EFOM model the calculation is done in annual basis and only seasonal changes can be taken into account. Consequently, e.g. variation of power production, consumption and cross-border trading are clearly out of the scope of the model. On the other hand EFOM enables estimating the cost effects of different kind of GHG abatement measures and long-term study period is naturally advantage in energy system analyses. Due to the nature of the model both capacity extension and replacement of present capacity are results of optimisation.

Simulating the wind power production in the energy system of Finland and in the electricity system of Nordic countries give consistent results: wind power will replace production in condensing power plants, mostly in coal fired plants, resulting in CO_2 abatement of 620–700 g CO_2/kWh wind power produced. The exact result depends on the amount of wind power added to the system, and the system inputs of how much coal and gas fired production there will be and at what operating costs. The dispatch of the system was simulated with two quite different assumptions: the system as it is today, and the system with foreseeable changes for year 2010 and a CO_2 tax for fuels. This changed the production form that was operating the margin considerably, as a shift from coal and oil fired plants to gas fired plants could be seen. However, as the amount of gas fired production was still limited in the system, wind power production would replace mostly coal fired production, and the combined effect of wind power production remained in the range of 620–700 g CO_2/kWh for the different simulations made. The simulations run are not directly comparable between the models EFOM and EMPS. The input for Finland for year 2010 is quite similar—slightly more coal fired production in EFOM and more imports in EMPS. The operating costs of the power plants are not on the same level due to the CO_2 tax used in EMPS, and the higher

Table 4
Overview of the simulated cases

Case	Model	Description
Reference 2000	EMPS	Simulation of the dispatch of Nordic electricity
Wind1, 2000		production with weekly time steps for the year 2000 (30
Wind2, 2000		different inflow and wind years). Reference case and
Wind3, 2000		increasing amounts of wind power production (16–46 TWh/a).
Reference 2010	EMPS	Simulation of the dispatch of Nordic electricity system
Wind1, 2010		with weekly time steps for the year 2010 (a possible
Wind2, 2010		scenario for the system, 30 different inflow and wind
Wind3, 2010		years). CO_2 taxes added to operating costs of thermal plants. Wind cases same as above.
Baseline	EFOM	25 years of simulation with 5-year time steps for the
Base-wind1		Finnish energy system. Business as usual scenario, no
Base-wind2		restrictions to GHG emissions, capacity extension by
Base-wind4		minimising the costs. Reference case and increasing
Base-wind7		amounts of wind power production set to year 2010 (1–7 TWh/a)
Kyoto	EFOM	25 years of simulation with 5-year time steps for the
Kyoto-wind1		Finnish energy system. Kyoto scenario, restrictions to
Kyoto-wind2		GHG emissions, capacity extension by minimising the
Kyoto-wind4		costs. Reference case and increasing amounts of wind
Kyoto-wind7		power production set to year 2010 (1–7 TWh/a)

natural gas prices in EFOM. However, as the amount of gas fired production is limited in Finland, this does not alter the results significantly.

The result that a significant amount of electricity produced by wind power in Norway and Sweden would replace fossil fired production in Central Europe can also have implications to energy policy. A country with huge renewable production and limited fossil fired production, that provides national policy support for wind, may not reap the direct CO_2 benefits of those investments. For international policy in Europe, the implications are more complicated. There are currently two market oriented mechanisms in planning phase for the reduction of CO_2 emissions. Tradable emission permits (TEP) affect the emissions directly, whereas the tradable green certificates (TGC) increase the use of renewable energies, which will reduce the CO_2 emissions indirectly. The interactions of the electricity market with TEP and TGC markets have been studied (Jensen and Skytte, 2002; Nese, 2002), and the results are somewhat ambiguous for the energy policy makers—it is not a straightforward relationship between the quotas and prices set by policymakers and the resulted emission savings. There might be problems especially with international trade of TGCs: as the CO_2 benefit is not tied into TGC, the country where it is most cost effective to build the renewable production will benefit the CO_2 reductions, paid for by other countries (Jensen and Skytte, 2002; Nese, 2002). Or then, if the CO_2 benefit is considered, this will result in domestic investments of renewables only, not taking the advantage offered by the international TGC's of building the renewable production where it is most cost effective (Morthorst, 2001). In these studies, it is assumed that renewable energy production reduces CO_2 emissions only in the country where it is built in—with the exception of TGCs increasing the consumer price for electricity with (slight) decrease in consumption. According to our simulations, in countries like Norway and Sweden the wind power production would result in reducing emissions elsewhere in the interconnected market area, which means that also the CO_2 emission benefits of wind power would partly be materialised in other country than where the wind power is installed. If wind power was built with f.ex. Germany's TGC funding in Norway (with better sites for wind power), this would result in part of the emission reduction in Germany. Emission reduction means also an increased amount of TEPs to be traded at the market. In this case it might help the international TGC system working, as the benefits will at least partly be for the country who is paying for the TGC.

There are three main assumptions used in the simulations: first the operating cost inputs, secondly assuming that all the large-scale wind production will be available in the system, and thirdly no considerations to stranded costs of fossil fired units.

The operating costs of thermal power are assumed to be according the inputs to the models. If there are emission limits or emission payments, or the prices of fuel change, this would alter the results of the models. For example if the price of gas becomes very expensive, the marginal (operating) costs of gas plants will become higher than the marginal costs of coal plants, and this would result in wind power replacing gas instead of coal. However, energy taxes normally reflect these changes—taken that the Kyoto targets must be achieved, there has to be some regulative ways to make the use of coal decrease. The difference in results in different scenarios is reflected in the Kyoto scenario simulations of the EFOM model for Finland: when emissions are restricted and the price of gas is assumed increasing substantially, the emission abatement of wind power (or other CO_2 free production forms) reduces to less than half than what it is today.

Assuming that the large-scale wind power is there in the system means that local grid connection issues as well as the system integration of wind power, would be taken care of. This is probably a good assumption for Norway and perhaps for Sweden also, meaning that the large hydro system will be able to absorb the increased hourly variations due to wind power. Wind power production is characterised with large hourly variations, and this might mean more regulating capacity has to be used than the existing hydro power—regulation is not modelled in the simulations and differences in regulation can therefore not be studied with these models. If the existing hydro power in the Nordic countries is not able to take care of the extra production swings seen by the system, this would mean using gas turbines or changing gas fired plants' production levels more and thus increasing the emissions due to that. For the wind power penetration levels studied here (1–10% of yearly electricity consumption) this will, however, not result in a significant amount of emissions for the whole of the Nordic area.

With large-scale wind production, also stranded costs of power production may come into question: this is when wind is replacing so much coal production that some plants need to be shut down even though they would otherwise still be economically viable to maintain. This has not been taken into account in the simulations made here.

5. Conclusions

The Nordic electricity market has been simulated with and without wind production to assess the effects of large-scale wind production on the market.

Results for weekly electricity flow and prices in the market area for different hydrological years can be obtained from the EMPS power market simulation model output. Wind power replaces mostly coal-condensing power and oil as fuel for electric boilers. For large amounts of wind power, 8–12% of consumption, also nuclear production is reduced some during wet years, mainly in Sweden. Reductions do not occur in the same countries as the wind production, e.g. coal-condensing power is replaced also in Central Europe. These results can have implications for energy policy, and should be taken into account while designing the TGC market in the area.

As a result of adding wind to 2 different scenarios for the Nordic system, CO_2 emissions will be reduced 700–620 g CO_2/kWh, according to the EMPS model simulations. According to the EFOM calculations the same result for CO_2 abatement holds in Finland in the Baseline scenario. In the Kyoto scenario in which it has been assumed that coal condensing power is prohibited in order to meet the Finnish Kyoto target new wind power capacity replaces the need for new natural gas combined-cycle capacity leading to CO_2 abatement of about 300 g CO_2/kWh. This case reflects the situation in the future, when there is possibly no more coal to be replaced.

The costs for CO_2 abatement by increasing wind power capacity in Finland seem to be about 20 Euro/t CO_2 at first and when the capacity is further increased the costs will also rise gradually to 35 Euro/t CO_2. In the Kyoto scenario the achievable CO_2 abatement is clearly lower due to significantly lower average CO_2 emissions from electricity production and therefore the abatement costs are higher, about 40–60 Euro/t CO_2.

These conclusions are made from simulations assuming that all the large-scale wind production will be available in the system. This means that local grid connection issues as well as the integration costs of wind power would be taken of. Hourly scheduling of thermal and hydro power with large wind production share will be questions for further study.

Acknowledgements

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Optimal electricity market for wind power

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Abstract

This paper is about electricity market operation when looking from the wind power producers' point of view. The focus in on market time horizons: how many hours there is between the closing and delivering the bids. The case is for the Nordic countries, the Nordpool electricity market and the Danish wind power production. Real data from year 2001 was used to study the benefits of a more flexible market to wind power producer. As a result of reduced regulating market costs from better hourly predictions to the market, wind power producer would gain up to 8% more if the time between market bids and delivery was shortened from the day ahead Elspot market (hourly bids by noon for 12–36 h ahead). An after sales market where surplus or deficit production could be traded 2 h before delivery could benefit the producer almost as much, gaining 7%.

Keywords: Wind power; Electricity market; Forecasting; Regulation market

1. Introduction

Nordpool is the largest electricity market in Europe with longest history, since the beginning of the 1990s. It is operating in the Nordic countries: Norway, Sweden, Finland and Denmark. In the spot market, hourly production can be traded. The market is cleared at noon, for the bids for the 24 h the following day, 12–36 h ahead. For Sweden and Finland, there exists also an after-sales market Elbas, which closes 1 h before delivery, with continuous trade.

Wind power is traded at the Nordpool electricity market already today, by the Danish companies. In the future, large-scale wind power production will be reality in many countries. The use of wind power as a renewable energy source is one of the means of achieving the greenhouse gas emission targets set in Kyoto agreement. Ways to push more wind into the electricity system, and the markets, would promote the use of renewables.

To realise the optimal market for wind power, this paper presents a case study based on 1 year wind and price data from Denmark. First the regulation needs of wind power is discussed. The current wind power forecast method is described and the forecast errors analysed. To quantify the benefits of operating in a shorter forecast horizon, the market calculation is made for different prediction horizons. To quantify the benefits of operating in a larger area for wind power production, the calculations are made by using simultaneous wind power data from the western and eastern parts of Denmark.

2. Regulation needs of wind power and market operation

The electricity production system provides a total amount of electricity, at each instant, corresponding to a varying load from the electricity consumption. The failure to keep the electricity system up has high and costly consequences, thus the reliability of the system has to be kept at a very high level. For the fast load variations, and unforeseen problems with production capacity, there are reserves at the system operator's disposal. The cost of reserves depends on what kind of production is used for regulation: hydropower being the cheapest option and gas turbines the most expensive one. Regulation power is nearly always at a higher cost than the bulk power available at the market. This is because it is used at short intervals only, and has to be kept ready so that continuous production by that

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capacity cannot be sold to the electricity spot market. Paying extra for regulation is also one incentive for the market actors to maintain their power balance.

Wind energy is renewable, mostly distributed generation characterised by large variations in the production. The intermittency of the wind power production, as well as the difficulties in predicting the production a day ahead, can cause difficulties for wind power producers acting in the market. If a substantial share of electricity comes from an intermittent power production with large variations, this will also increase the amount of regulation power needed in the system. This is because the system operator has to prepare for unforeseen large variations in the production, in addition to load swings and outages of production capacity. Information from a well working forecasting method for wind power would ease this problem, and is needed as soon as wind power variations are becoming as large as the variations of load. The costs of increased regulation will be passed on to the consumers by prices of system services, and the production capacity providing for this extra regulation will gain.

Traditionally, looking at system operation, wind power forecasts have a value to the system. Day-ahead forecasts help the scheduling of conventional units: planning the start-ups and shut-downs of slow starting units in an optimised way, keeping the units running at best possible efficiency, saves fuel and thus operational costs of the power plants. Forecasts 1–2 h ahead help keeping up the optimal amount of regulating capacity at the system operators' use. Keeping too little reserves risks the adequacy of power, which is crucial in power systems. Keeping too much reserve makes running the system expensive. Simulations of system operation with different levels of wind power prediction errors show that minimising prediction error increases the benefits by the wind plant measured as fuel savings from the conventional units. However, both the system in question (production mix and load variations) and the properties of wind power production (correlation with load) have a strong effect on the results of how much benefit the improved predictions bring about (Milligan et al., 1995). Simulations of the England–Wales system show that the prediction errors begin to affect the system fossil fuel costs when the wind power penetration is about 8% (of yearly energy, 13% of the capacity installed). At large wind power penetrations (20–30% of energy), wind production forecasts can increase the savings in total fuel costs by 13–35% (Watson et al., 1999). For the hydro-dominated Swedish system, the decrease of efficiency in the hydro system due to the uncertainty (forecast errors) of wind power production has been simulated. Wind power would need to be produced 1% more to compensate for the losses of hydro power production, when wind power production is 4% of yearly electricity consumption in Sweden (Söder, 1994).

Today, as we are acting at liberalised electricity markets, the unit commitment and scheduling is done to a large extent by the market: supply and demand bid to the market, which is settled at the most cost-effective way for each hour, day ahead. Also regulating power can be sold and bought at a market, closing an hour before, or even during the operating hour. The system operators still have duties, because keeping up the system needs the balance to hold at every instant, so the ancillary services provided by the system operators include the allocation and operation reserves. In this situation, there is still value in wind power forecasts. All the producers with wind power in their generation mix, bidding to the market, need a forecast to base their bids on. With a forecast, they can count their wind power capacity when making a bid, selling all possible production. Forecast errors result in supplying a different amount of energy than the bid, and this will be penalised—buying power from the regulating market results in extra costs and thus reduced net income for the operator. The market design in this respect, that is how much the deviations of original bids to the market are penalised, can have a considerable effect on the wind power producer. The Dutch system of rewarding overproduction with only 16 Euro/MWh and penalising power not delivered with 120 Euro/MWh will result in dropping the net income of a wind power producer to less than half, if 25% of the production is badly predicted (Hutting and Clejne, 1999). In a Danish study (Nielsen et al., 1999) the deviations of wind power production due to mispredictions will impose a 1.3–2.7 Euro/MWh extra cost from settling the deviations at balancing market. Market design can also change the bidding strategy from simply minimising the error in energy (Bathurst et al., 2002; Nielsen and Ravn, 2003).

For the system operator, the situation has not changed when it comes to the duty of keeping the system running despite all load and production swings, and optimising the use of reserves. When there is a considerable amount of wind power in the area, accurate knowledge of wind power production still helps to reduce the reserves needed for unforeseeable swings in production. With electricity markets, also the regulation power can be traded at the market, so also the regulation power available at neighbouring countries can be used.

There will always be prediction errors for the load as well. The load forecasts are typically more accurate, with long experience and more predictable diurnal and seasonal patterns. This is why the operation in electricity markets will be more difficult for wind power producers than for other actors. The form of an electricity market that would enable wind power producers acting in the market in an optimal, cost effective way, is one of the questions in this paper.

3. Description of the electricity system in Denmark

West and East part of Denmark are separate two areas, not connected by transmission lines, and part of separate electricity systems, Central Europe's UCTE (West part) and Scandinavian Nordel (East part). They both have transmission lines to Germany and Sweden, and in addition West Denmark to Norway (Fig. 1). In this paper, the main focus is on the Western part, where the largest part of the wind power production resides in Denmark. In Denmark, the independent system operators Eltra (western Denmark) and Elkraft System (eastern Denmark) are responsible for the prioritised production, which is most of the wind power plants in the area and small combined heat and power plants (CHP).

Eltra is the balance responsible market player for 80% of the installed wind power in Denmark. The prioritised production accounted for about half of 2001 total demand (20.9 TWh) for the area: wind power 3.4 TWh (16%) and local CHP 6.8 TWh. The total installed wind capacity is already larger than the off-peak load level, also in wintertime (Table 1) (Hilger, 2002). At times, wind power production is close to the total consumption in the area. In 2002, wind power production has reached instantaneous penetration of 100% during 1 h, which is unique in the world. Eltra bids a part of wind energy production in the daily spot market, thus avoiding the rescheduling of other production units in the area.

In the Eastern part of Denmark, Elkraft System is balance responsible for approximately 20% of the installed wind power in Denmark. The prioritised production accounted for about 25% of 2001 total demand for the area, wind energy about 6%. The total installed wind capacity relative to demand is approximately half of off-peak load levels.

Table 1
Capacity at Eltra area (western Denmark) in 2001

	Capacity (MW)
Central CHP	3200
Local CHP	1520
Wind power	1930
Interconnection to Norway	1000
Interconnection to Sweden	630
Interconnection to Germany	1200
Peak demand	3700

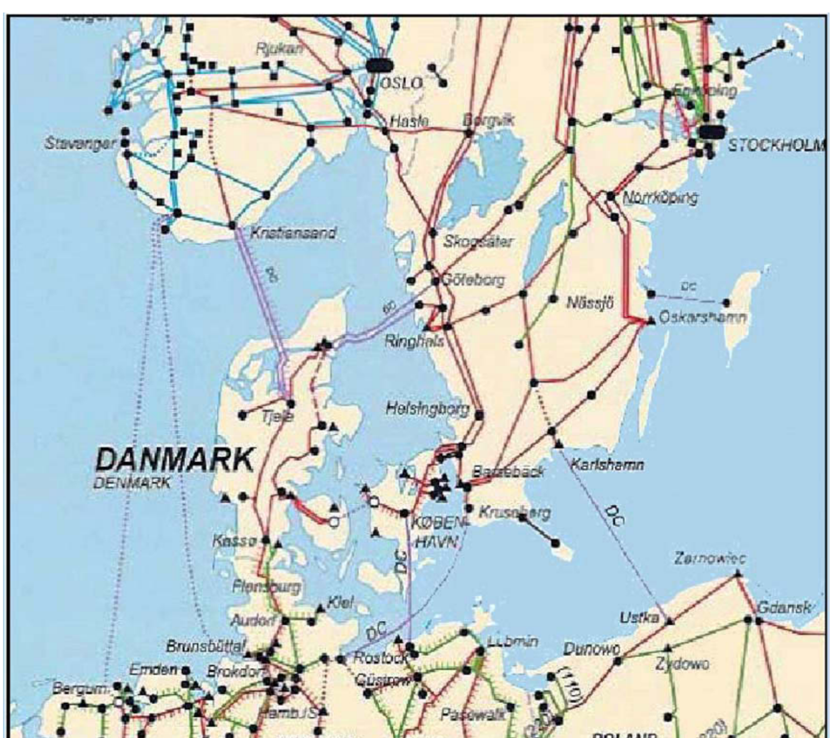

Fig. 1. The area and transmission lines of Denmark: the western part is the Jutland peninsula and island Fyn, the largest islands on the eastern part are Zealand and Lolland. (*Source*: Hilger, 2002).

4. Forecasting wind power production

4.1. Wind power prediction tool WPPT

Wind Power Prediction Tool (WPPT) has been developed in collaboration with Eltra/Elsam and Informatics and Mathematical Modelling (IMM) at the Technical University of Denmark (DTU). The development work for the first version was initiated in 1992. In 2001, the example year used in this paper, the version WPPT 2 was used. The next version was to be implemented in 2003.

The model is based on statistical time series modelling taking as input the weather forecast for wind as well as the on-line measurements of wind power production for selected reference wind farms. The model produces power production estimates for the reference wind farms, each representing a sub-area, and up-scales the production estimates for the sub-areas. Finally, the total prediction for the area is the sum of the predictions for sub-areas (Nielsen and Madsen, 2000). The predictions are made for 39 h ahead and updated half hourly.

The on-line measurements have negligible weight on prediction horizons of more than 12–18 h. The wind speed forecasts from the national weather service are obtained 4 times a day. The resolution for the HIRLAM model is 17 km, and the forecast wind speed will be interpolated between the grid points for each of the 14 reference wind farms. The WPPT model is correcting the meteorological wind speed estimates for their tendency of producing larger wind speed values for longer time horizons as well as their lack of taking into account site specific diurnal variation.

4.2. Forecast errors

Taking the year 2001 as an example, the predictions were compared to the actual production in Eltra area (western Denmark). The data comprised wind power predictions as made by WPPT model during operation in 2001, and actual, measured wind power production of Eltra area. One August week of missing predictions was excluded from the data. To see how much the prediction error increases with increasing forecast horizon, the predicted wind power production at different prediction horizons were compared to the actual production.

The correlation of predicted wind power production and actual wind power production keeps at a quite high level during the whole of the prediction horizon, above 0.90 for the first 12 h and above 0.80 for up to 30 h ahead (Nielsen and Madsen, 2000). Correlation tells us of the ability of the predictions to follow the ups and downs of the wind production.

When forecasting 6 h ahead, the error for the installed capacity of about 1900 MW wind power was between ± 100 MW for 61% of time. Large errors (more than 500 MW) occurred during nearly 1% of time. When forecasting 36 h ahead, the errors were relatively small (inside ± 100 MW) 37% of time and large errors (outside ± 500 MW) occurred during 7% of time. The mean error of the predictions is near zero, but there is a slight bias to the positive error side (predicted wind power more than realised).

In Fig. 2 the total error during the whole year has been calculated for different prediction horizons. It is presented as % of total realised production. For comparison, persistence assumes that the production will be the same at $t+k$ hours as at t hours. For short time horizons, up till 3 h, the persistence gives good

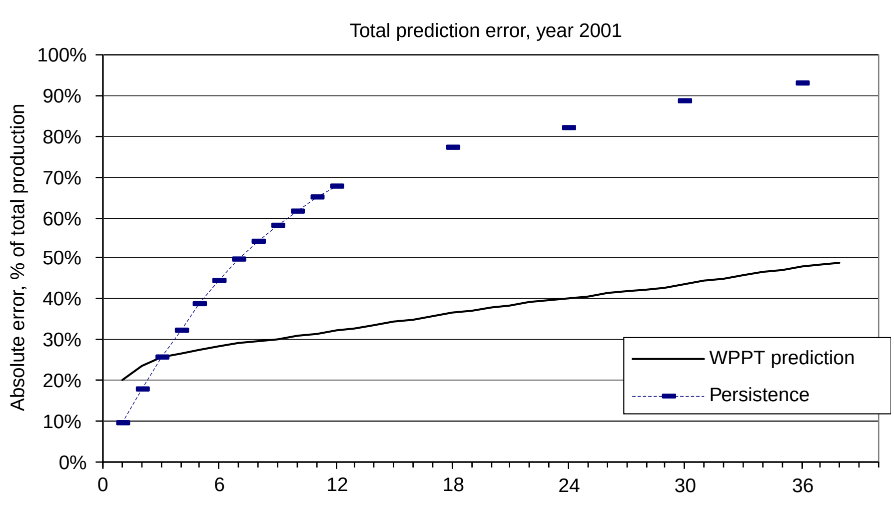

Fig. 2. The total absolute prediction error (sum) during 1 year for different prediction horizons, as percentage of the total realised production in 2001.

results, even better than the WPPT. This is partly because there is no access on-line to the whole production of the area and in the WPPT model of year 2001 the up-scaling the production was not up-to-date.

The proportion of energy that will be known x hours before can be seen from Fig. 2, showing the total absolute error from predictions x hours ahead, divided by total production. Assuming the same level of production ahead as presently (persistence), 90% of energy will be known 1 h before. From the WPPT model, 70% of the energy will be known 9 h before, 60% of energy will be known 24 h before and only 50% of energy will be known 36 h before. The forecast errors here are larger than usually presented, which is due to calculating in total energy instead of % of installed capacity. For Nordpool electricity market (prediction horizon 13–37 h ahead), the mean absolute error (MAE) is 8–9% of installed capacity. However, for market operation this results in 38% of yearly production mispredicted.

The forecast horizon is here taken from the constantly updated values of WPPT, however, the longer predictions are based on weather forecasts, which are only updated 4 times daily. It takes about 3 h for the new forecast to come out in the WPPT output. The actual forecast horizon is thus 3–9 h longer than stated here.

Fig. 2 reveals the difficulty of acting at the market: even though the overall shape of the production curve can be predicted, the exact hourly value of wind power production is difficult to forecast 7–38 h ahead. This results in 30–50% of the total energy being forecasted wrongly. It has to be noted, however, that this is not the latest state-of-the-art of the forecasting models, improvements are expected in the future.

4.3. Improvements to the wind power forecasts in the future

Wind power forecasting day ahead is still new and the models are constantly subject to improvements (e.g. Landberg, 1994; Giebel et al., 2003). The variations of wind power production in northern European latitudes occur due to weather systems passing the area, causing high winds, which calm down again. Forecasting wind power production relies on forecasted wind speeds in the area. The largest error component in the wind power production forecasts is the input from the weather forecast models. Meteorological institute weather service forecasts for wind speed and direction are not very accurate—partly because so far exact values at space and time have not been crucial for other applications. An accuracy of ± 2 m/s and ± 3 h has been enough. For wind energy, however, this results in large errors in a day-ahead hourly market.

There are currently several projects running aiming at improvements both for the weather forecasts and the statistical model part. Running the weather forecast models with several input values (ensemble forecasting) should give information on the uncertainty of the wind speed forecast, and also help choose the right wind speed forecast as a basis for wind power predictions. The next version of WPPT will improve the on-line data and up-scaling (Nielsen et al., 2002). The reference wind parks selected in 1996 are no longer representative for the sub-areas. Wind power capacity of 600 MW in western Denmark at the end of 1996 is now more than 2000 MW at the end of 2002, and the average size of the turbines has increased dramatically. Taking into account wind direction dependency has been observed to improve the forecasts for most of the sites (Nielsen, 1999).

Getting better knowledge of on-line wind power production in the area will improve both the short-term forecasts and the up-scaling and estimation procedures of the statistical prediction model. Getting better accuracy for weather forecasts for wind, as well as other improvements described above, will improve the medium and long-term (12–36 h) forecasts. It is difficult to state the future accuracy, but the improvements could be of the order of 20–50% of the accuracy today.

Load forecasts have been studied for decades. However, it will not be possible to get to the same level of accuracy with wind power predictions as the load predictions are. Electricity consumption behaves with predictable diurnal and seasonal patterns, when looking at larger areas, with errors in the order of about 1.5–3% of peak load, corresponding to an error of about 3–5% of total energy, when forecasting day ahead.

4.4. Reduction of prediction error in a larger area

There is also value in making the forecasts for a larger area—when the weather fronts pass over the area, forecasting the time some hours wrong for one site does not always mean it is wrong for the whole area. Wind power prediction errors cancel out to some extent when the area is larger (Focken et al., 2001). Making a production forecast to only one wind park results in more errors than making the forecast to tens or hundreds of wind parks covering a larger area. The same applies for load forecasting: predicting one load produces large errors compared to predicting the load in a larger area with hundreds of individual loads.

For system operation, the knowledge of wind power forecasts can be derived either by making a prediction for wind power production in the whole system area, or by aggregating the information of all the wind power bids in the market, so basically there is no difference in the information. However, for a producer owning only one wind park, there will be a considerable difference in income relying on forecasts for only that site compared with a joint operation in the markets with several wind parks distributed over a larger area.

For the effect of prediction errors smoothing out in a larger area, the data was analysed to see the errors separately compared with the possibility of operating wind power in co-operation between West and East part of Denmark.

In western Denmark, the wind parks have as a largest distance North–South less than 300 km and East–West less than 200 km (Fig. 1). In the eastern part of Denmark, the wind parks are spread over area of 200 km (N–S) by 100 km (E–W) (excluding the Bornholm island). Together, the distance between wind parks can be 300 km in East–West direction. The installed wind power capacity in 2001 was about 550 MW in the East compared with nearly 2000 MW in the West.

Simultaneous prediction and production data were available from the system operators in Denmark, Elkraft and Eltra. Comparative data was available for updates 4 times a day, that is why the comparison is here made on Nordpool market predictions, for 12–36 h ahead. Four days (in February and September) were removed from the data because of missing prediction data in Elkraft data. With the missing 1 week of Eltra data this results in 8440 h of comparable data for the year 2001.

The tool used for wind power prediction in Elkraft System was developed in-house. The key elements are essentially the same as already described for WPPT, i.e., the bases are the weather forecasts for wind and on-line measurements of wind farms.

The initial total prediction errors in a 12–36 h market were 1.28 TWh for Eltra (West) and 0.33 TWh for Elkraft (East). For 35% of the time, the prediction error was to opposite directions in the West and East. This results in the total prediction error for the whole area being 1.47 TWh instead of 1.61 TWh just adding up the two (a 9% reduction in the prediction error).

If there were twice as much wind power as today in Elkraft area, a 12% reduction would happen, and if Elkraft's production were the same as Eltra's, a 14% reduction would happen in the prediction error when combining the two areas instead of calculating them separately. In both these calculations a simple up scaling was performed. The development in reduction (9–12–14%) reflects that the reduction will be relatively larger if the wind power capacities in the two areas are closer to being identical.

5. Wind power acting on day ahead electricity market

5.1. Case study Eltra at Nordpool Elspot market

The market calculation is here made assuming different times between the bids and the delivery. Hourly data for year 2001 was used for

- wind power production: actual, measured production of Eltra area in West Denmark,
- wind power predictions: as made by Eltra/WPPT model during operation in 2001,
- market prices: Nordpool ELSPOT area price for West Denmark, Odense and
- prices for regulation market in western Denmark: for up- and down-regulation.

During the example year 2001, there was 1 week with faulty operation of the WPPT, due to missing weather forecasts. So the time period studied here is 2.1–16.8 and 25.8–31.12. The Nordpool prices during the time are presented in Table 2 and Fig. 3.

The predicted time series for Nordpool was calculated from the 11 o'clock prediction the previous day for hours 0:00–24:00 next day, that is 13–37 h ahead predictions updated once a day. The bids for the market have to be given until 12:00 the previous day, so 1 h was given for the operator to make the bid to the market. Actually the forecast horizon is longer, as the forecasts are mainly based on weather forecasts, and they are calculated based on input values from 6 o'clock. Taking several hours to run the weather forecast model at DMI, the results will be available for WPPT model at about 9 o'clock.

The predicted time series for a more flexible market (6–12 h ahead) were calculated as 7–13 h ahead predictions updated four times a day to produce the forecasts for the next day: from the predictions at 17:00 (→ 00:00–05:00), 23:00 (→ 06:00–11:00), 5:00 (→ 12:00–17:00) and 11:00 (→ 18:00–23:00) hours. Example of 1 month for the predicted wind power production calculated in two ways, together with the measured production, can be seen in Fig. 4.

A third calculation was made for a constantly operating market for hourly production, with bids closing 1 h before. As 1 h was again left for the operator to make the bids, this meant using the information 2 h before for the wind power prediction. The best prediction type here is the persistence, using the realised wind

Table 2
Market price level for area Denmark west during example year 2001 (7.45 DKK/Euro)

2.1–16.8, 25.8–31.12, 2001	Nordpool ELSPOT	Regulation down	Regulation up
Average price Eur/MWh	23.7	12.3	30.2
Min price Eur/MWh	0.9	−0.7	8.0
Max price Eur/MWh	268.8	40.9	214.7

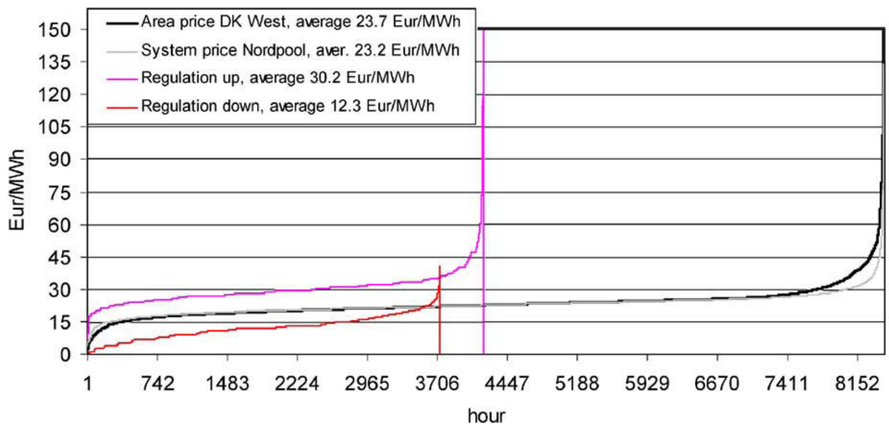

Fig. 3. Market price data from Denmark West, year 2001, as duration curves. Regulation price exists only for either up or down for each hour. There are 135 h that the up-regulation price is above 46 Eur/MWh, maximum price is 214.7 Eur/MWh. The West Denmark area price is 140 h above 46 Eur/MWh, maximum 268.7 Eur/MWh (system price 55 h and 238.4 Eur/MWh, respectively).

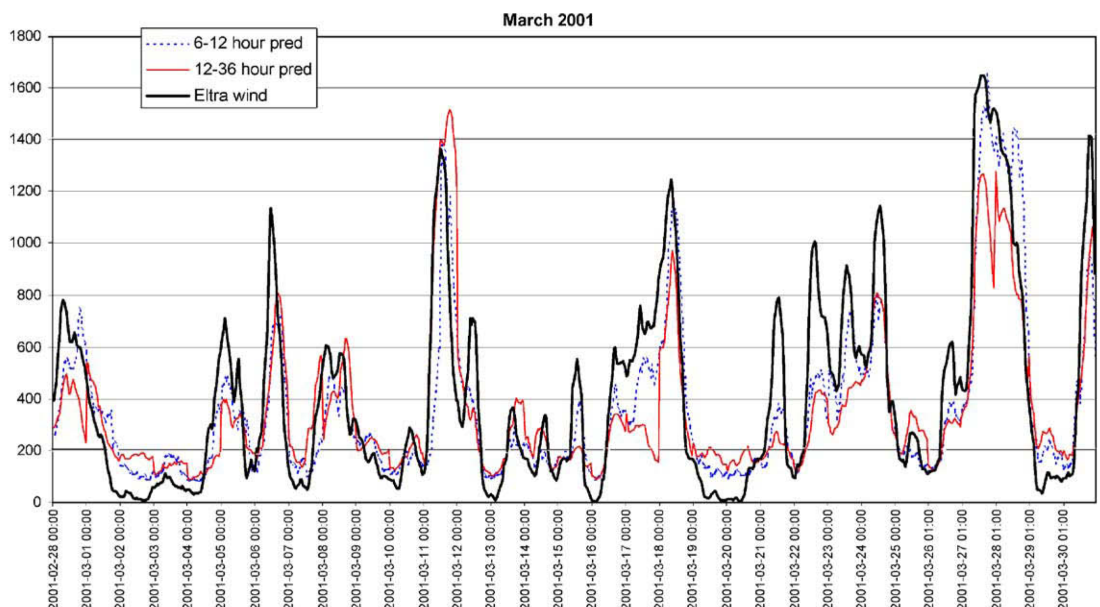

Fig. 4. Example of the predictions made to the Nordpool market (12–36 h) and to a more flexible market (6–12 h) compared to the realised production (Eltra wind), during 1 month.

power production 2 h before as the estimate for current hour. This is not something available today, as the measured information for thousands of wind turbines is not on-line. It is however used here to show what could be achieved in the future. Actually, WPPT improves the 2 h forecast already notably, so with either good on-line measurements or good, representative reference wind farms and up scaling in the future, the 2–3 h-ahead prediction can also improve in the future.

The income from the market and the cost of regulation were calculated in the following way. Income I for the hour i is the predicted power $\hat{P}_i$ times Nordpool area price for West Denmark p_{spot}:

$$I_i = \hat{P}_i p_{\text{spot}}. \tag{1}$$

Cost c for the hour i is prediction error times regulation price p_{reg}. When wind power producer produces less than what has been bid to the market, the missing part will have to be purchased at up-regulation price, which is higher than the spot price received from the market. When wind power production is higher than the bid to the market, the surplus production is sold at down-regulation price, which is lower than the spot price, resulting in a negative cost in formula (2). Down-regulation price can be negative, resulting in a cost instead of just lower income than if the prediction had been correct:

$$c_i = (\hat{P}_i - P_i)p_{\text{reg}}. \tag{2}$$

In Denmark, the so-called two-price model in the settlement of imbalances is used. This means that regulation price exists only for either up or down at each hour, depending on the direction of the system imbalance. Only when imbalances according to wind power prediction errors increase system imbalances, the regulation prices apply. When wind power prediction errors are in the opposite direction—i.e. "help the system to balance"—imbalances are priced at Nordpool spot price (Fig. 5). The imbalance of wind power was to the same direction as system imbalance about 70% of time in 2001. For the remaining 30% of time, when wind power imbalance is actually helping the system balance, the spot price is used for the imbalance, resulting in wind power being paid according to realised production. Finally, the net income is the income subtracted by costs, for the whole time period:

$$I_{\mathrm{TOTAL}} = \sum_i I_i - c_i. \tag{3}$$

The results are presented in Table 3.

If there were no forecast errors, the average price from Nordpool (area West Denmark) for wind power would be 22.9 Eur/MWh (average area price 23.7 Eur/MWh). Wind power seems to be influencing the area price, as there is more difference in the price for wind power compared with average area prices than there is for the system price of Nordpool (average 23.2 Eur/MWh, wind power 23.0 Eur/MWh).

For Nordpool 12–36 h market, prediction error for the year totals 0.68 TWh predicted too high and 0.67 TWh too low. This means that 39% of the total yearly energy was predicted wrong. Taking into account that during some hours (about 30% of time) the imbalance caused by wind power was to opposite direction than system imbalance, and wind power income was calculated for the realised production, this results in 31% of wind power production to be balanced at the regulation market. For a 6–12 h market, prediction error for the year totals 0.52 TWh predicted too high and 0.53 TWh too low. This means that 30% of the total yearly energy would have been predicted wrong, and 21% of the production had to be balanced at the regulation market. For a constantly operating hourly market, using persistence from 2 h before as the bid for wind power, 18% of the energy would be mispredicted, and 10% of the production would have to be balanced at the regulation market.

A more flexible market, allowing the bids for wind power to be updated 6–12 h before, would reduce the regulation costs by 30% and increase the net income by 4% from 20.1 to 20.9 Eur/MWh. An hourly operation, using persistence estimation from 2 h before, would reduce the regulation costs for nearly 70% and increase the net income by 8% to 21.8 Eur/MWh.

Because of the regulation costs and varying prices in the market, there are some hours that the net income of wind power producer would be negative, that is, the regulation costs exceed the spot income. For Nordpool market (12–36 h), about 8% of the time there is no net income but costs. For a more flexible market (6–12 h) this reduces to 6% of the time. Hourly operation would nearly end negative cash flow situations (only 0.3% of the time). All the negative net income situations in 2001 occurred due to high prices of up-regulation. In theory, in situations where negative income would arise with negative down-regulation prices, wind power could limit the production of some of the farms.

Table 3
Income and costs for wind power producer in western Denmark, with and without forecasts, calculated from 2001 data

2.1.–16.8, 25.8–31.12, 2001	Realised production	13–37 h forecasts	7–13 h forecasts	2–3 h persistence
Total (sum) TWh	3.35	3.36	3.34	3.35
Min, MW	0	48	49	0
Max, MW	1731	1899	1899	1731
Average, MW	392	394	391	392
Prediction error, up/down as % of total 3.35 TWh		20%/19%	15%/15%	9%/9%
Income Nordpool Elspot, average Eur/MWh	22.9	22.9	22.9	22.8
Income Nordpool Elspot, predicted and realised production[a]				
average Eur/MWh		22.4	22.4	22.5
Regulation: up/down				
% of time		40%/29%	37%/27%	28%/25%
% of energy		15%/16%	10%/11%	5%/5%
Average price Eur/MWh		30.1/13.8	30.6/13.3	29.4/13.4
Regulation costs				
Eur/MWh regulated		5.9	5.2	3.8
Eur/MWh produced		2.3	1.5	0.7
Net income Nordpool				
Average Eur/MWh	22.9	20.1	20.9	21.8

[a] This takes into account the 30% of time when no regulation market price exists for wind power, as the imbalance is to opposite direction of system imbalance. During those hours the income is calculated from the realised production, not the predicted one.

5.2. Case study—Eltra using after sales market like Elbas

If an after sales tool was at a wind power producer's disposal, the correction of prediction errors could for a large part be traded at markets, instead of paying penalties for it. Elbas is a market like that, operating currently in Finland and Sweden. The trade closes 1 h before delivery. This enables the wind power producer to look at the production level 1–2 h before, when the production level is already known more accurately than 13–37 h before, and trade the over- or under-predicted amount at Elbas. Taking the price series from Elbas market for year 2001, it was estimated how much the wind power producer would gain in this way.

There is for every hour a range of prices available from Elbas, because the market is continuous and you can trade for each hour's production constantly up to 1 h before, as long as there is a buyer taking your offer to sell and vice versa. The minimum price was used for the situations when wind power would need to sell the surplus production, and the maximum price was used when more power was needed to fulfil the bid made for wind power production. There was a price at Elbas for 92% of the time (Fig. 6), for the remaining 8% of the time of the year 2001, all the error in prediction was corrected at regulation market, in the same way as in the previous Section 5.1.

The Swedish area price for Elbas represents what the Danish price would be, except for cases of bottlenecks of transmission capacity between the areas. In bottleneck cases the areas have a different price. In 2001, this was about 25% of the time. The direction of bottleneck is also relevant: if the bottleneck is to transmission towards Sweden and there is overproduction of wind power that needs to be sold to Sweden, it is a bottleneck that matters in this calculation. The same applies for bottlenecks that are for transmission towards West Denmark. Taking the direction of the bottlenecks into account, leaves us with 13% of time when there has been a bottleneck the Swedish Elbas price data for Denmark has been used. For these hours the assumption that similar prices would exist in Denmark if they had the same after sales market has been made.

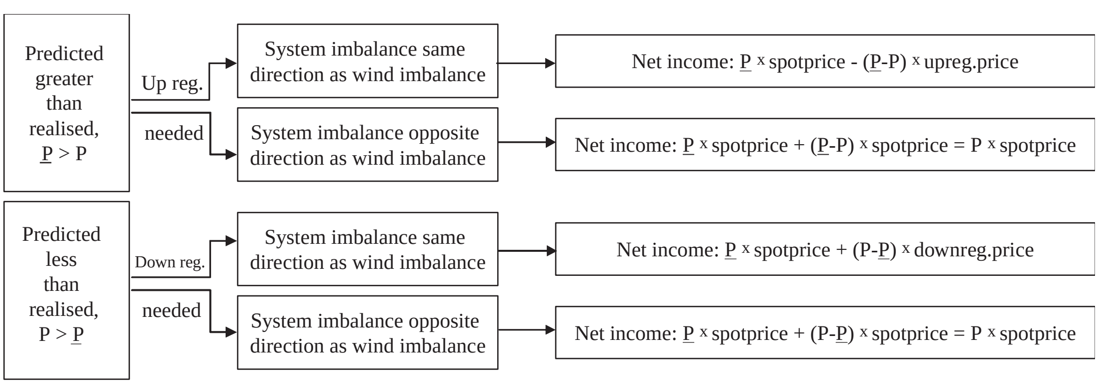

Fig. 5. Selling wind power in the Nordpool market with West Denmark regulation market.

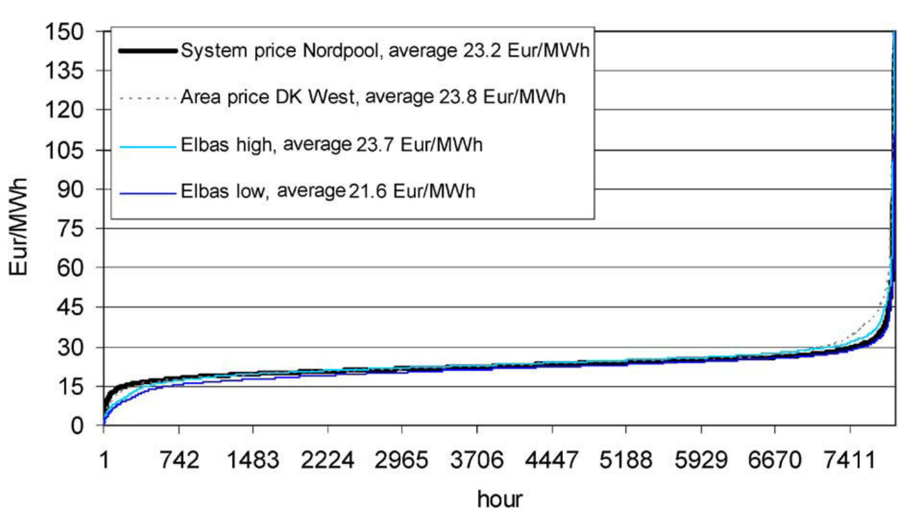

Fig. 6. Prices at Elbas market in 2001, compared with Nordpool system prices and the area price for Denmark West, as duration curves for the hours for which Elbas price exists (7858 h). The maximum price at Elbas was 241 Eur/MWh, and the price was above 46 Eur/MWh 79 h for the highest realised and 43 h for the lowest realised price.

Now the same calculation as for previous chapter is done, where the wind power producer first gets an income from Nordpool Elspot for the bids according to 13–37 h ahead prediction at the Odense area price. This results in the same original income for the producer of 22.9 Eur/MWh, for the total 3.3 TWh predicted to be produced during the year.

With the predictions 2–3 h ahead, like in the previous section, the producer trades the difference of the original bid and the now more accurate prediction in Elbas market. For each hour there will be either a cost (from buying the missing production, at the highest realised Elbas price) or income (from selling the surplus production, at the lowest realised Elbas price). From 2001 data, there was slightly more buying than selling, so that the net cost was 1.6 Eur/MWh (cost per trading amount 1.2 TWh, for the total wind power production the cost is 0.6 Eur/MWh).

For regulating market, only 0.4 TWh needed to be adjusted, coming from the amount each hour that differed from 2–3 h-ahead prediction. This 0.4 TWh includes also some hours of larger prediction errors, from the 12–36 h prediction, for the 8% of time with no Elbas price. Regulating market costs were 3.9 Eur/MWh regulated or 0.7 Eur/MWh total produced. The net income is Elspot income—net cost from Elbas—regulating market cost, 22.9–0.6–0.8 Eur/MWh, and results in 21.5 Eur/MWh total produced for 2001.

This result shows that with an after sales tool, the net income for a wind power producer can be close to what it would be if the market was designed to be a short and flexible one (21.5 Eur/MWh compared with 1–2 h market calculation 21.8 Eur/MWh in Table 3). The result here for wind power at Elbas market assumes that the price level of the after sales market stays most of the time near the day-ahead spot market prices. This means that wind power is not influencing the after sales market price, at least not more than the here assumed lowest-price-for-selling and highest-price-for-buying.

6. Conclusions and discussion

Wind power production, on an hourly level for 1–2 days ahead, is more difficult to predict than other production forms, or the load. The overall shape of the production curve can be predicted using weather forecasts and time series analysis. However, the high peaks of wind power production are difficult to predict at hourly levels for both the exact amount and the exact occurrence in time. For the prediction models in use in Denmark in 2001, the errors amounted to 30–50% of the total energy being forecasted wrong, when forecasting the exact hourly value of wind power production 7–38 h ahead. It has to be noted, however, that this is not the latest state-of-the-art of the forecasting models, improvements are expected in the future.

Combining the predictions for East and West Denmark would result in a reduction of prediction error. For 35% of the time, the prediction errors for a 12–36 h ahead market are to opposite directions. The prediction error of the combined two areas would be 9% less than simply summing up their separate prediction errors. The prediction error would decrease more if the wind power capacity would be more identical in the two areas—by simple up-scaling of the production in the East to the same level as in the West—a 14% reduction in error would be achieved.

The predictions were analysed together with the electricity market prices for Denmark, using actual data from year 2001. The income for wind power in West Denmark, not taking the prediction errors into account, would have resulted in 22.9 Eur/MWh (average spot price for the area 23.7 Eur/MWh). When bidding the forecasted production to the market, the income for wind power producer is 22.4 Eur/MWh taking into account the hours (nearly 30% of time) when spot price applies for the realised production, not the predicted one. In the two-price model in the settlement of imbalances, there is regulation market price for the imbalance only when the imbalance is to the same direction as the system (net) imbalance. Costs from the regulation market for the prediction errors for 12–36 h ahead market were 2.3 Eur/MWh total wind power production, resulting in net income of 20.1 Eur/MWh. A cost of 2.6 Eur/MWh for the payment of real time imbalance of power has been reported from West Denmark for year 2000, so this calculation is well in line (Eriksen et al., 2002).

A more flexible market, allowing the bids for wind power to be updated 4 times daily, with predictions of 6–12 h ahead, would reduce the regulation costs for 30% and increase the net income by 4%. Hourly operation, using persistence estimation from 2 h before, would reduce the regulation costs for 70% and increase the net income by 8%. Using an after sales tool like Elbas for trading the estimated surplus or missing production 2 h before delivery would reduce the regulation costs by 70% and increase the net income by 7%.

The results are based on year 2001 data of West Denmark, where wind power penetration is considerable and can be seen to influence the prices. The assumption has been made, that the same price level would apply when shortening the time between bids and delivery, not taking into account the implications of a shorter market to other production forms and actors. For Elbas after sales prices, no impact of wind power production or bottlenecks to the price level has been assumed. If the price level at regulating market was higher in penalising the imbalances, the benefit for a flexible market, or after-sales tool, could be greater. On the other hand, acting at flexible markets could also bring about extra trading costs.

For a wind power producer, selling his production at a market, there is a clear benefit for trading as close to the delivery as possible, because this reduces the prediction errors and thus extra costs from regulating. Also forecasting for a larger area also improves the forecasts and reduces the error. With an after sales market, the situation can also be improved for the producer.

Market design can have a strong influence on new, renewable, intermittent production forms like wind power. For the power system, all imbalances do not need to be balanced one-by-one, only the net imbalance. In a large system this results in considerable benefit, when most of the individual imbalances counteract one another. This should be reflected by the regulating market as well. For example the two-price model in the settlement of imbalances in use in Denmark only penalises the ones having their imbalance in the same direction as the system (net) imbalance. However, it does not take into account that only part of this imbalance needs to be corrected (the net imbalance), as in the market the ones having their imbalance to the opposite direction help the system. For example in Norway, the ones having their imbalance to the opposite direction than the system actually gain. As the imbalance for wind power is about the same to both direction, this results in almost no extra regulation costs for wind power in Norway (Gustafsson, 2002). In California the imbalance for wind power is calculated as the average over a month, which also results in near zero imbalance costs for wind power (Caldwell, 2002).

With the current day-ahead market, an after sales tool like Elbas for trading the mispredicted amounts of wind power would help the wind power producers. However, looking from the power system point of view, it is not necessary to trade some amounts of wind power production back and forth, especially in a case where several individual wind power producers would try to reach the bid production amounts this way. The rules for the market have been set for producers that can influence their production amounts. For them, penalising imbalances is the economic incentive for everyone to make the effort in keeping the balance, thus helping the system operators. For production form like wind power, it may however result in unoptimal operation in the market for the individual producers. This might also be one incentive for forming larger wind power producers' pools taking the benefits for reduction of forecasting errors in larger geographical areas.

There is no technical barrier in making the electricity market more flexible that is, shortening the time between the clearing of the market and the delivery. This can be done by introducing new products to the market, as well. With more flexible mechanisms than what is in use today, there is the possibility to ease the integration of wind power to the system. A well working after sales market could help both wind power producers and the system operator, in reducing the amount and cost of wind power at the regulating market. However, looking from the power system point of view, only the net imbalance has to be dealt with, so unnecessary trading back and forth for individual producers is not the optimal solution.

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Title

The impact of large scale wind power production on the Nordic electricity system

Abstract

This thesis studies the impact of large amounts of wind power on the Nordic electricity system. The impact on both the technical operation of the power system and the electricity market are investigated.

The variability of wind power is reduced when looking at a large interconnected system with geographically dispersed wind power production. In the Nordic countries, the aggregated wind power production will stay between 1–90 % of the installed capacity and the hourly step changes will be within ±5 % of the installed capacity for most of the time. The reserve requirement for the system, due to wind power, is determined by combining the variations with varying electricity consumption. The increase in reserve requirement is mostly seen on the 15 minutes to 1 hour time scale. The operating reserves in the Nordic countries should be increased by an amount corresponding to about 2 % of wind power capacity when wind power produces 10 % of yearly gross demand. The increased cost of regulation is of the order of 1 €/MWh at 10 % penetration and 2 €/MWh at 20 % penetration. This cost is halved if the investment costs for new reserve capacity are omitted and only the increased use of reserves is taken into account. In addition, prediction errors in wind power day ahead will appear in the regulating power market to an extent which depends on how much they affect the system net balance and how much the balance responsible players will correct the deviations before the actual operating hour.

Simulations of increasing wind power in the Nordic electricity system show that wind power would mainly replace coal fired production and increase transmission between the areas within the Nordic countries and from Nordic countries to Central Europe. The CO_2 emissions decrease from an initial 700 gCO_2/kWh to 620 gCO_2/kWh at 12 % penetration. High penetrations of wind power will lower the Nordpool spot market prices by about 2 €/MWh per 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand).

Keywords
wind power, power systems, power system impacts, wind power variations, power generation, renewable energy sources, fluctuating production, predictability of wind power, electricity markets, emission reductions, CO^2 abatement, Nordic countries, simulation

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This thesis studies the impact of large amounts of wind power on the Nordic electricity system. The impact on both the technical operation of the power system and the electricity market are investigated. The drawbacks of wind power, from the power system point of view, are its variability and unpredictability. However, these problems are greatly reduced when wind power is connected to larger power systems, which can take advantage of the natural diversity in variable sources. Large geographical spreading of wind power will reduce variability, increase predictability and decrease the occasions with near zero or peak output. The increase in reserve requirement due to wind power impacts on thermal and hydro power operation as well as to the electricity market are discussed.

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